Assessing the Hedging Value of Wind Against Natural Gas Price Volatility

by
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List of Acronyms

AEO	Annual Energy Outlook
AWEA	American Wind Energy Association
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
IRP	Integrated Resource Plan
GWh	Gigawatt hour
FERC	Federal Energy Regulatory Commission
LBNL	Lawrence Berkeley National Laboratory
MATS	Mercury and Air Toxics Standards
MMBtu	Million British Thermal Units
MWh	Megawatt hour
NGCC	Natural gas combined cycle plant
NPV	Net present value
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
PSC	Public Service Commission
PTC	Production Tax Credit
PUC	Public Utility Commission
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
SERC	Southeast Electric Reliability Council
TVA	Tennessee Valley Authority

Abstract

In recent years, natural gas prices in the U.S. have reached historic lows and utilities have been rapidly replacing coal with gas-fired generation. Natural gas prices are historically volatile, and overreliance on natural gas can lead to high electricity prices in the event of rising fuel costs or price spikes. We examine how utilities can use wind energy from long-term power purchase agreements (PPAs) as a tool to hedge against natural gas price volatility and future environmental regulations. We assess how federal and state policies affect wind's hedging value, and provide a case study on how utilities in the Southeast are increasingly importing wind from high capacity regions.

We quantify wind's hedging value by comparing the net present value (NPV) of investment costs for a natural gas combined cycle plant with and without wind generation to meet future demand under uncertainty. We use wind prices from the Lawrence Berkeley National Laboratory national wind PPA sample, and analyze six investment options over a 30-year period using the U.S. Energy Information Administration's (EIA) AEO 2013 natural gas price scenarios with and without carbon tax, and our own scenarios created using Monte Carlo simulation and Random Walk.

Assuming a least-cost framework, we find that the utility would only invest in gas generation under the EIA reference scenario. In our model, the utility will have an NPV cost band from $4.7 to $10.1 billion if they do not hedge with wind, whereas if they add 20% wind to their portfolio, the maximum cost will decrease by $774 million if the worst-case gas price scenario were to occur. By procuring wind energy at fixed prices through long-term PPAs, utilities can reduce their exposure to unfavorable cost outcomes, particularly if a carbon tax of $10 per ton or more is enacted.

Acknowledgments

We would like to thank Jonas Monast, Emily Klein, and especially Dave Hoppock and Dalia Patino-Echeverri for their generous guidance throughout this project. We also thank Mark Bolinger at Lawrence Berkeley National Laboratory for his valuable insight and help procuring wind power purchase agreement data.

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Executive Summary

In recent years, electric utilities have been rapidly replacing coal with gas-fired generation as natural gas prices in the U.S. have reached historic lows. Natural gas prices are unpredictable, however, and overreliance on gas can lead to high electricity prices in the event of gas price spikes or increasing fuel costs. In this paper, we examine how utilities can use wind generation as a tool to hedge against natural gas price volatility and future environmental regulations. We compare investment costs for a natural gas power plant with and without wind generation to meet demand under gas price uncertainty, and find that adding wind will reduce utilities' portfolio risk. We also assess the role of federal and state policies in incentivizing wind, and provide a case study on how utilities in the Southeast are increasingly importing wind from high capacity regions through long-term power purchase agreements.

Introduction

The U.S. electricity market has seen a dramatic change in recent years as natural gas prices have reached historic lows and the market share of gas-fired electric power generation has grown. Coal has traditionally been the largest source of electricity generation, comprising 37% in 2012, but with low natural gas prices and environmental regulations on the horizon, utilities are increasingly retiring coal plants in favor of adding natural gas plants.[1] The power sector's demand for gas is projected to double in the next 20 years,[2] and the U.S. Energy Information Administration (EIA) estimates that by 2040, gas-fired generation will overtake coal (Figure 1).[3]

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[1] U.S. Energy Information Administration, *Today in Energy: 27 gigawatts of coal-fired capacity to retire over next five years,* July 27, 2012, accessed February 20, 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=7290. Plant owners reported 27 GW of planned coal retirements from 2012 to 2016.

[2] Black & Veatch, "2013 Energy Market Outlook and Industry Trends," July 16, 2013, accessed January 10, 2014, http://bv.com/docs/reports-studies/2013-energy-market-outlook-and-industry-trends.pdf.

[3] U.S. Energy Information Administration, *AEO2014 Early Release Overview,* December 13, 2013, accessed February 13, 2014, http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm.

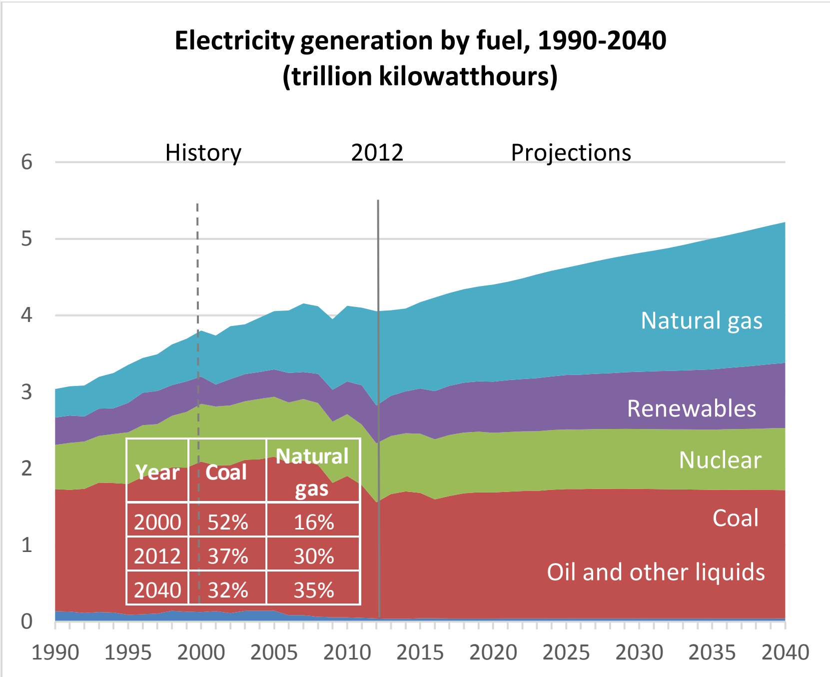

Figure 1. Electricity generation by fuel from 1990 to 2040[4]
Source: EIA

Given that fuel costs account for 85% of the total operating costs of an efficient combined gas cycle natural gas plant (NGCC), overreliance on gas generation leaves utilities exposed to significant price risk.[5] Utilities can mitigate this risk in the short term by using financial tools such as futures and swap contracts, but there is no way to lock in a long-term hedge against rising prices, which are illustrated by the NYMEX gas futures strip in Figure 2. In addition, natural gas prices are also highly unpredictable, exhibiting twice the volatility of oil prices.[6] This makes it very difficult for a utility to estimate their future costs when investing in new natural gas-fired generation.

[4] U.S. Energy Information Administration, *Annual Energy Outlook 2013*, Washington D.C.: U.S. Energy Information Administration (2013).
[5] Mark Bolinger, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices,* LBNL-6103E, Lawrence Berkeley National Laboratory (2013): 2.
[6] Massachusetts Institute of Technology, *The Future of Natural Gas,* MIT Energy Initiative (2011).

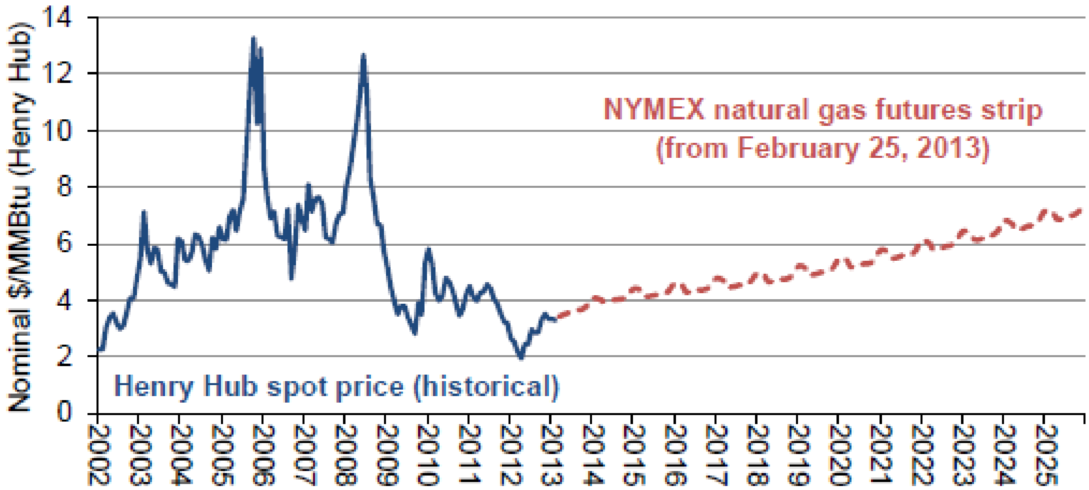

Figure 2. Historical Henry Hub Natural Gas Prices and NYMEX Gas Futures Strip[7]
Source: (Bolinger, Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices 2013)

Recently, utilities have begun to incorporate renewable energy in their portfolios to hedge against this fuel price risk, either by building renewable generation or signing power purchase agreements (PPAs), which guarantee fixed energy costs over 15 to 25 years.[8] Like natural gas prices, wind energy prices have also reached historic lows, and utilities large and small are currently taking advantage of these competitive wind prices by signing long-term wind PPAs to import energy into their service territories.[9]

While wind PPA prices may not be least cost compared to gas-fired generation, wind offers many long-term hedging attributes.[10] Wind generation does not have variable fuel costs and can function as a fuel saver, displacing more expensive gas-fired generation. Wind also does not incur water availability risk in contrast to coal, gas, and nuclear power. Similar to other forms of renewable generation, wind does not produce direct carbon emissions or emit pollutants, making it an ideal hedging tool against future environmental regulations.

Like renewables in general, however, wind power faces significant challenges as an intermittent or naturally varying resource since it cannot be dispatched like traditional generation to meet

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[7] Bolinger, *Long-Term Hedge Value of Wind*, 9.
[8] National Renewable Energy Laboratory, "Power Purchase Agreement Checklist for State and Local Governments," (2009).
[9] American Wind Energy Association, "AWEA U.S. Wind Industry Fourth Quarter 2013 Market Report," (2014).
[10] Bolinger, *Long-Term Hedge Value of Wind*.

demand.[11] Also, wind projects have a high upfront capital cost compared with NGCC plants, and this combined with low natural gas prices have made it difficult for wind to compete with gas-fired generation in the wholesale electricity market.[12] While natural gas prices are projected to increase, they are expected to remain low since the U.S. has a large amount of gas reserves being developed.[13]

When deciding how to meet future electricity demand, utility investors face great uncertainty surrounding fuel costs and regulations, which makes wind a viable hedging tool. This project presents methods for assessing the hedging value of wind in a generation portfolio. Below, we review background information about wind generation in the U.S., discuss the Lawrence Berkeley National Laboratory's (LBNL) wind PPA price sample that we use in our analysis, describe the method of our investment option decision model, and present our results and conclusion as highlighted by recent wind investment decisions made by utilities in the Southeast.

Background

Wind power in the U.S.

Currently, there is 61,100 MW of wind capacity installed in the U.S,[14] and in 2013, wind accounted for 6% of capacity nationally and 4% of all electricity generated.[15] Wind turbines harness kinetic energy to generate electricity, and high-speed winds are most abundant in the interior region of the U.S. (Figure 3). Wind energy prices are lowest in the "wind belt," which stretches from Texas to North Dakota. Of all the states, Texas has the most capacity installed at 12,200 MW, with California and Iowa following at 5,500 MW and 5,100 MW respectively.[16]

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[11] April Lee, Owen Zinaman, and Jeffrey Logan, *Opportunities for Synergy Between Natural Gas and Energy in the Electric Power and Transportation Sectors,* No. NREL/TP-6A50-56324, National Renewable Energy Laboratory (2012): 21.
[12] Bolinger, *Long-Term Hedge Value of Wind*.
[13] EIA, *Annual Energy Outlook 2013*, 89.
[14] AWEA, "Fourth Quarter 2013 Market Report."
[15] EIA, "Monthly Energy Review." February 2014, accessed January 20, 2014, http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf.
[16] AWEA, "Fourth Quarter 2013 Market Report."

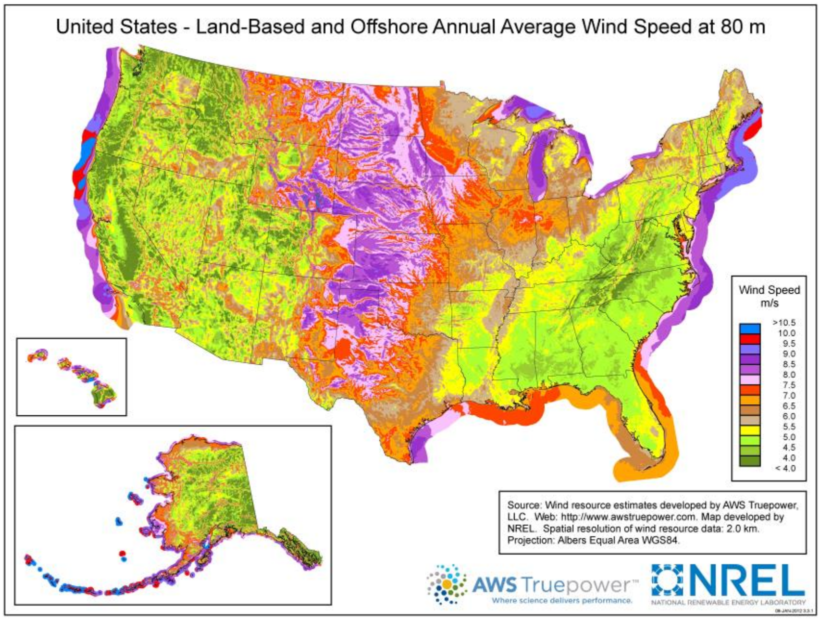

Figure 3. U.S. wind speeds map at 80 meter hub height[17]
Source: NREL

Wind capacity additions have grown significantly since 2006 (Figure 4), spurred on by federal and state policies and incentives, and decreasing installation and turbine costs.[18] In 2012, a record-breaking 13,131 MW of wind capacity was added, while in 2013 only 1,100 MW was added due to uncertainty surrounding the expiration of the production tax credit (PTC), a federal incentive for wind.[19] First implemented as part of the Energy Policy Act in 1992, the PTC gives wind suppliers a credit of 2.2 cents per kilowatt hour of wind generated for ten years. Since then, the credit has expired five times, most recently in December 2013,[20] and it is unclear when and whether Congress will renew the credit next. Although Congress revised the policy in January 2013 to extend the credit to wind farms that started construction by 2014, the uncertainty was enough to dampen

[17] National Renewable Energy Laboratory, *Dynamic Maps, GIS Data & Analysis Tools: Wind Maps,* 2014, accessed February 10, 2014, http://www.nrel.gov/gis/wind.html. . Hub height is the distance from the ground to the center of the rotor, not including the blades. The average hub height and rotor diameter have been increasing in size over time, leading to higher capacity factors for wind, especially in low wind resource areas.
[18] AWEA, "Fourth Quarter 2013 Market Report." Capital costs have dropped 43% in the past four years (American Wind Energy Association 2014).
[19] Mark Bolinger and Ryan Wiser, *2012 Wind Technologies Market Report,* U.S. Department of Energy (2013): 3.
[20] Database of State Incentives for Renewables & Efficiency, *Renewable Electricity Production Tax Credit (PTC),* accessed February 20, 2014, http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F .

growth of the wind industry.[21] Without the PTC, the cost of wind may increase as much as $23 per MWh, making it economically uncompetitive with traditional sources of generation.[22]

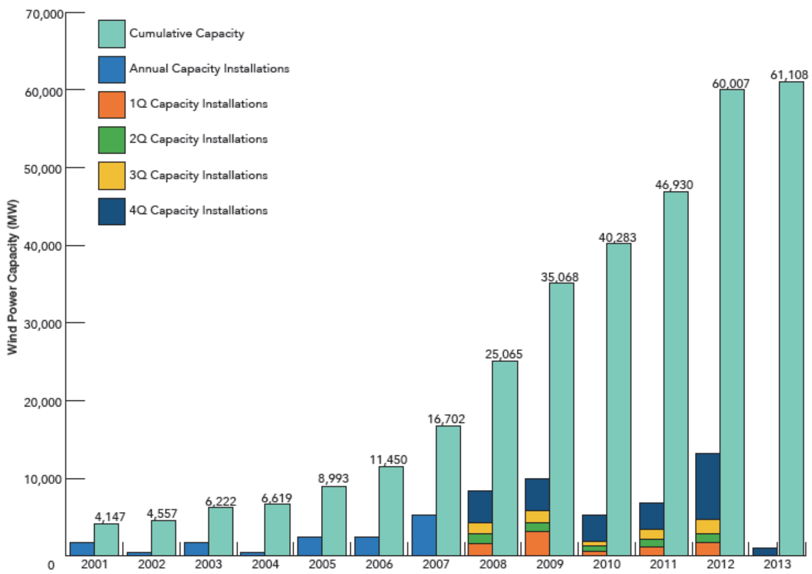

Figure 4. Wind Capacity Growth in the U.S. from 2001 to 2013[23]
Source: AWEA

Wind penetration has also been driven by state policies such as renewable portfolio standards (RPS). State RPS require producers to generate a percentage of their electricity from renewable sources such as wind, solar, geothermal, and biomass.[24] Currently, 29 states and Washington DC have mandatory RPS programs and 8 states have renewable portfolio goals (Figure 5).[25] RPS have been an important driver of wind installations in the absence of a federal standard. From 1999 to 2012, 69% of national wind power capacity was built in states with RPS programs.[26] According to a study by Lawrence Berkeley, current RPS targets require less yearly capacity additions than the recent annual growth of wind, however, making it unlikely that they will be the main driver of wind deployment.[27] For states to meet RPS targets by 2020, they must add 3 to 5 GW of total renewable capacity per year, of which wind is only a fraction.[28] During the record year of wind additions in

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[21] Database of State Incentives for Renewables & Efficiency, *Rules, Regulations & Policies for Renewable Energy,* accessed February 10, 2014, http://www.dsireusa.org/summarytables/rrpre.cfm.
[22] Bolinger, *Long-Term Hedge Value of Wind*.
[23] AWEA, "Fourth Quarter 2013 Market Report."
[24] EIA, *Today in Energy: Most states have Renewable Portfolio Standards,* February 3, 2012, accessed February 19, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=4850.
[25] Database of State Incentives, *Rules, Regulations & Policies for Renewable Energy.*
[26] Bolinger and Wiser, *2012 Wind Technologies Market Report*, 56.
[27] *Ibid*., 56.
[28] *Ibid*., 56.

2012, more than 11,000 MW was ordered in states that did not have near-term RPS targets.[29] In these states, federal and state tax credits drove investment in projects such that the cost of wind energy was economically competitive even without RPS.[30]

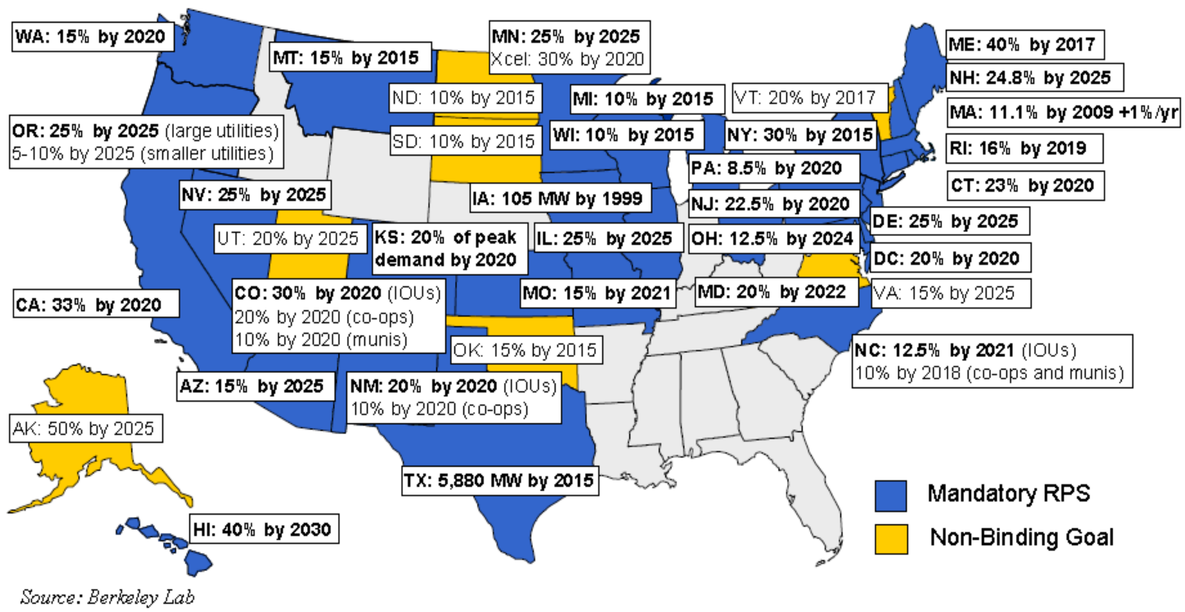

Figure 5. State Renewable Portfolio Standards and Goals in the U.S. as of 2013[31]
Source: LBNL

Wind development is also dependent on transmission to connect the high load centers with the high wind resource areas. In the past five years, more than 11,000 miles of new transmission was added.[32] There are still challenges with siting and planning new lines, however, which could limit the amount of wind development. Multi-state transmission projects are subject to state and federal regulation, and it often takes longer to build new transmission than it does to develop a wind farm.[33]

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29 Bolinger and Wiser, *2012 Wind Technologies Market Report*, 3.
30 Bolinger and Wiser, *2012 Wind Technologies Market Report*, 3. Some states have proposed bills that repeal or decrease RPS targets.
31 Lawrence Berkeley National Laboratory, *Renewables Portfolio Standards Resources,* accessed December 2, 2013, http://emp.lbl.gov/rps.
32 Bolinger and Wiser, *2012 Wind Technologies Market Report*, ix.
33 Andrew Mills, Ryan Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*, Berkeley: LBNL (2009).

Wind capacity additions are also facilitated by power purchase agreements or multiyear contracts between a seller and buyer for the sale and purchase of electricity and the associated renewable energy credits (RECs) or for the credits only.[34] In 2013, 60 agreements totaling 8,000 MW were made, and 5,200 MW of these PPAs have yet to start construction.[35] Utilities of various sizes, large companies, and institutions have been signing wind PPAs for different motivations. For example, in 2012 Ohio State University agreed to a 20-year contract for 50 MW of power from a wind farm in Ohio in order to go beyond buying renewable energy credits to meet their carbon neutrality goal.[36] Private companies such as Microsoft and Google are using 20-year wind PPAs to hedge against the cost of energy at their data centers, while utilities such as Xcel Energy of Colorado have signed PPAs to lock in the price of wind at $25 to $35/MWh.[37] As Ben Fowke, the CEO of Xcel, states, "it works out to a very good levelized cost for our customers…. These prices are so compelling, the energy [cost] associated with it is less than you can do locking in a 20-year gas strip."[38]

Utilities are also buying wind for the associated renewable energy credits (RECs). Also known as green certificates, RECs are tradable instruments that can be used to comply with voluntary targets or compliance requirements. One REC represents 1 MWh of electricity generated from a renewable source such as wind, solar or landfill methane gas,[39] and can be sold bundled with or without the electricity at the retail level.[40] RECs do not need to be scheduled and can be used independently of when the electricity was generated. Utilities in the Southeast that have signed wind PPAs are also buying the RECs, which they can either retire, sell separately from the generation, or allot to their green power program customers.[41]

Wind Power Purchase Agreement Price Trends

Like natural gas prices, wind PPA prices have been decreasing in recent years, making wind competitive with other forms of generation in the electricity market. To assess the hedging value of

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[34] U.S. Environmental Protection Agency, "Guide to Purchasing Green Power: Renewable Electricity, Renewable Energy Certificates, and On-Site Renewable Generation," (2010).
[35] AWEA, "Fourth Quarter 2013 Market Report."
[36] Ohio State University, *Ohio State to power campus with wind energy from Ohio wind farm,* October 1, 2012, accessed February 20, 2014, http://www.osu.edu/news/newsitem3521.
[37] AWEA, "Fourth Quarter 2013 Market Report."
[38] AWEA, "Fourth Quarter 2013 Market Report."
[39] EPA, "Guide to Purchasing Green Power," 10.
[40] J Heeter and T Nicholas, *Status and Trends in the U.S. Voluntary Green Power Market (2012 Data),* National Renewable Energy Laboratory (2013).
[41] Alabama Power, *Environmental News,* accessed February 15, 2014, http://www.alabamapower.com/environment/news/chisholm-view-project-provides-low-cost-power.asp.

wind in a generation portfolio, we referred to a national sample of wind PPA prices compiled by Lawrence Berkeley National Laboratory. The sample includes 287 agreements for 23.5 GW of wind capacity built from 1997 on in 29 states.[42] In 2012, the national average price was $38/MWh, with regional variations in the prices reflecting the capacity factor of that region (Figure 6).[43]

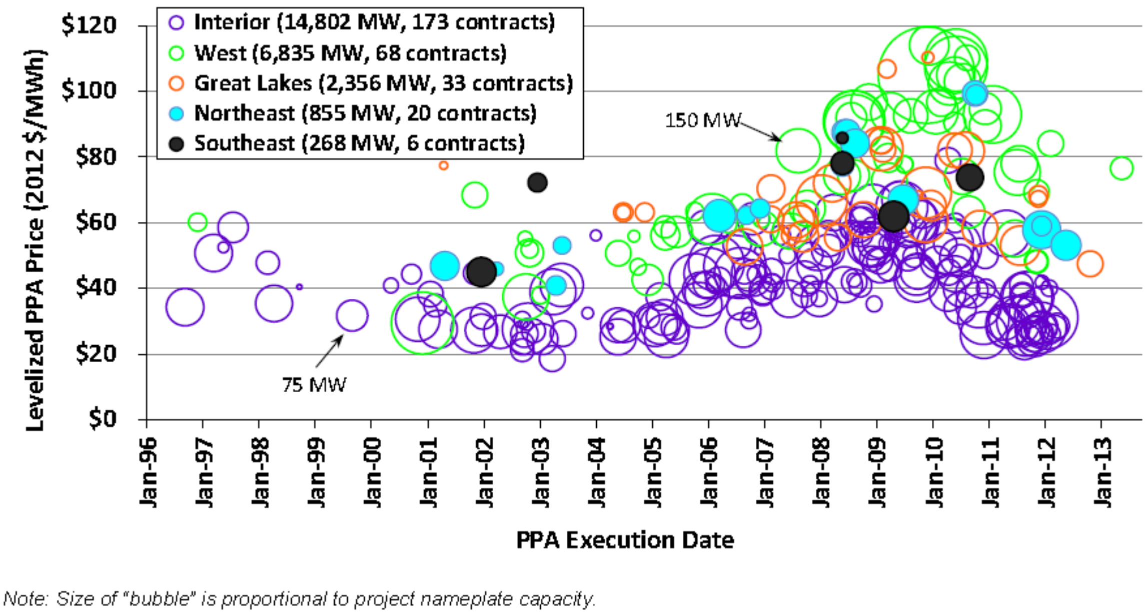

Figure 6. Levelized Wind Power Purchase Agreement Prices by PPA Execution Date and Region[44]
Source: (Bolinger and Wiser, 2012 Wind Technologies Market Report 2013)

Most PPAs are for 20 years or longer and have a fixed cost with no annual increase throughout the life of the contract, while the PPAs with escalators increase at an average rate of 2.4% per year to account for inflation.[45] The prices are assumed to reflect the PTC and other incentives that were received, and in all agreements the buyer receives the RECs.[46]

Natural Gas Markets and Financial Hedging Tools

In the U.S., natural gas is traded in 16 different locations for physical delivery. Henry Hub in Louisiana is the principal hub for the natural gas market because of its central location and the

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[42] Bolinger, *Long-Term Hedge Value of Wind.*
[43] Bolinger and Wiser, *2012 Wind Technologies Market Report.*
[44] *Ibid.*
[45] Bolinger, *Long-Term Hedge Value of Wind*, 7.
[46] *Ibid.*

volume it trades. Daily and monthly transactions are offered, and its price is the reference point for North American natural gas markets.[47] It is the delivery point for the New York Mercantile Exchange's (NYMEX) natural gas futures contracts, which are agreements between a buyer and seller for the delivery of a certain quantity of gas at a set price to Henry Hub during a specific month.[48] Futures contracts range from 1 to 120 months, and only a small percentage of contracts on the exchange are traded forward for longer than 36 months, making it difficult to secure long-term contracts for natural gas.[49]

Other short-term financial tools traded on the exchange include options, collars, and swap contracts, which fix the transportation costs from Henry Hub to the physical delivery locations.[50] Using these tools, buyers can limit their exposure to extreme natural gas prices instead of procuring gas at spot prices or current market rates.[51] According to the Brattle Group, "while the expected costs for gas are the same with or without the hedging strategy," by hedging, buyers can "reduce the distribution of potential outcomes relative to being unhedged."[52]

Electric utilities can also implement hedging programs for fuel if they are approved by state public utility commissions (PUCs). Commissions review utilities' total costs, which include new capital investments and financial hedging tools, and determine which costs are prudent and recoverable.[53] PUCs also set the electricity prices that regulated utilities can charge through a ratemaking process.[54] Many PUCs only allow utilities to hedge against natural gas price volatility for three to five years out, since losses on financial tools can lead to large costs for utilities and ratepayers.[55] Natural gas is often the "marginal, price-setting fuel in power markets," and it is in commissioners' interest to find out how utilities can reduce customer exposure to gas price volatility.[56] In contrast to financial hedging tools, wind can be used as a long-term hedge against gas price volatility since wind PPAs ensure a fixed price of energy over a period of 15 to 25 years.

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[47] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Market Basics,* (2012): 33.
[48] The Brattle Group, "Managing Natural Gas Price Volatility: Principles and Practices Across the Industry," (2010):, 11.
[49] Brattle Group, "Managing Natural Gas," 11.
[50] *Ibid*., 29.
[51] *Ibid*., 18.
[52] *Ibid*., 18.
[53] Massachusetts Institute of Technology, *The Future of the Electric Grid,* MIT Energy Initiative (2011): 177.
[54] MIT, *The Future of the Electric Grid,* 177.
[55] Lisa Huber, *Utility-Scale Wind and Natural Gas Volatility,* Snowmass: Rocky Mountain Institute (2012).
[56] Brattle Group, "Managing Natural Gas," 6.

Assessing the Hedging Benefits of Wind Generation

Utility Investment Decision Model

For this analysis, we developed a utility investment decision model for investors to quantify the hedging value of wind in their generation portfolio. We consider alternatives for an investor to meet 1,356 MW of future power demand and 8.9 GWh of additional energy demand (equivalent to a 75% capacity factor) with six options that range from building a new natural gas combined cycle plant, using a combination of NGCC and wind, and buying wind only. As shown in Table 1, the NG 80% to NG 20% options include combinations where wind PPAs are used to displace gas generation:

Table 1. Six investment options

Investment Options	Generation Mix	NGCC Capacity (MW)	Total Capital Requirement (million 2011 $)	Number of gas turbines
NG 100%	NGCC 100%, Wind 0%	1356	1414.6	5
NG 80%	NGCC 80%, Wind 20%	1085	1143.5	4
NG 60%	NGCC 60%, Wind 40%	814	864.9	3
NG 40%	NGCC 40%, Wind 60%	542	583.5	2
NG 20%	NGCC 20%, Wind 80%	271	298.4	1
NG 0%	NGCC 0%, Wind 100%	0	0	0

We assume that the investor is a large utility in a large balancing authority that has other baseload capacity to balance the high wind options. While the utility can invest in other forms of generation, we only consider NGCC and wind in these options since they comprise most of the new capacity installed over the past 15 years.[57] We use a discount rate of 7% and assume that the annual electricity demand does not change over the 30-year investment period. The outcomes for our model are the net present value (NPV) of future costs (expressed in real 2011 dollars) over the investment period.

[57] EIA, *Today in Energy: Natural gas, renewables dominate electric capacity additions in first half of 2012,* August 20, 2012, accessed March 20, 2014, www.eia.gov/todayinenergy/detail.cfm?id=7610.

As shown in Figure 7, we conduct different types of analysis on the six options to see which investment the PUC will choose under the least-cost decision framework,[58] and consider the potential risk for each option.

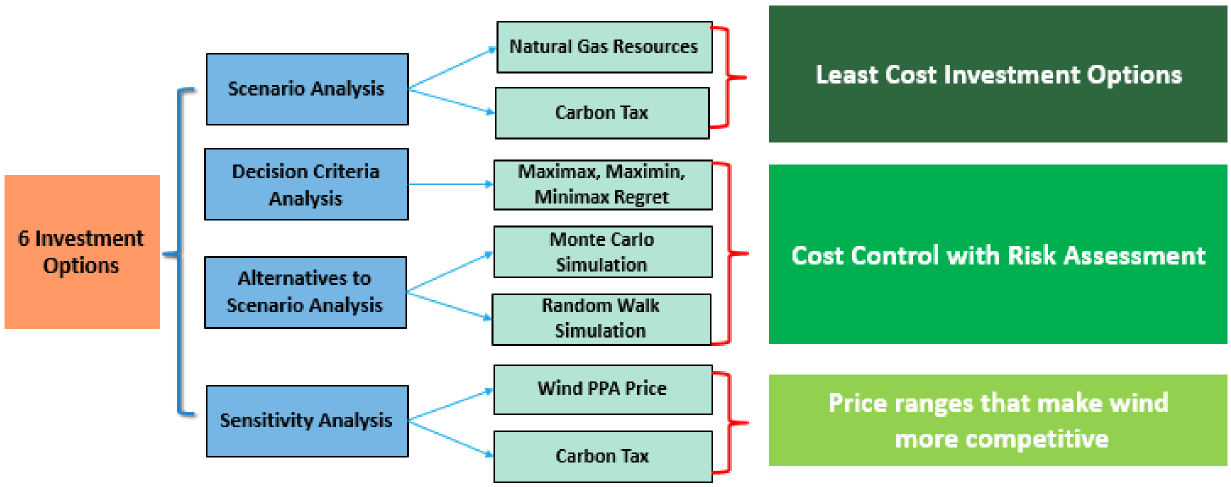

Figure 7. Four types of analysis for the utility investment decision model – the green boxes on the right show the objectives for each analysis.

For our wind options, we refer to the national wind PPA sample compiled by Lawrence Berkeley where the average wind PPA price across the sample is approximately $50/MWh in 2011 dollars.[59] Adding integration and transmission costs of $5/MWh,[60] we use a fixed PPA price of $55/MWh with no annual increase over the 30-year contract. We compare these costs to the cost of building and operating a new NGCC plant with GE 7FA gas turbines and a wet cooling system.[61]

Scenario Analysis

To account for the uncertainty in NPV costs with regards to fuel prices and environmental regulations, PUCs and utilities conduct scenario analysis across potential futures to determine investment option costs across a range of potential futures. As shown in Table 2, we use six scenarios based on different assumptions about future natural gas and carbon tax prices. The scenarios come from the U.S. Energy Information Administration (EIA), which generates reference

[58] David Hoppock, Dalia Patino-Echeverri, and Sarah Adair, *Assessing the Risk of Utility Investments in a Least-Cost-Planning Framework,* NI WP 13-07. Duke University (2013).
[59] Bolinger, *Long-Term Hedge Value of Wind.*
[60] *Ibid.*
[61] To create the investment options, we used the Integrated Environmental Control Model (IECM) to find capital costs and operating and maintenance costs for a new NGCC plant with a 75% capacity factor and a lead time of 2.5 years.

and side cases using the National Energy Modeling System and publishes them in their Annual Energy Outlook (AEO).[62] Federal and state regulations that are in effect at the time are included the AEO 2013 reference case, while pending or proposed regulations such as a carbon tax are not. The production tax credit, which expired on December 31, 2013, is not assumed to be renewed in the AEO 2013 cases.

Table 2. Six scenarios based on different natural gas resource estimates and carbon tax futures

	Scenario Name	Corresponding scenario in AEO 2013
EIA projections without carbon tax	EIA Reference Case	Reference Case
	Low NG Price Case	High EUR Case
	High NG Price Case	Low EUR Case
EIA projections with carbon tax	GHG $10 Case	GHG $10 Case
	GHG $15 Case	GHG $15 Case
	GHG $25 Case	GHG $25 Case

In the EIA reference case, Henry Hub spot prices are projected to increase by an average of 2.4% per year from $4 per MMBtu in 2013 to $8 per MMBtu in 2040 due to the continued cost of developing incremental production and the expected exports.[63] The Low Natural Gas Price and High Gas Price cases correspond to side cases in AEO 2013 – the high oil and gas resource case has low price projections assuming an abundant supply of gas, and the low oil and gas resource case has high price projections assuming a limited supply (Figure 8). For the high resource case, the estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is assumed to be 100% higher and the amount of undiscovered resources in lower 48 offshore states and Alaska is 50% higher than in the reference case, while for the low resource case, it is estimated to be 50% lower than the reference.[64] In these EIA scenarios, we use the average delivered natural gas price to the electric sector as forecasted in AEO 2013.[65]

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[62] The National Energy Modeling System (NEMS) is an energy-economy modular system specific to the U.S. that is used by the EIA to model alternative energy policies and different assumptions about energy markets and project their economic, environmental, and energy impacts.
[63] EIA, *Annual Energy Outlook 2013*.
[64] *Ibid.*
[65] EIA, *Natural Gas Supply, Disposition, and Prices.* 2013, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=3-AEO2013&table=13-AEO2013&region=0-0&cases=lowresource-d012813a,highresource-d021413a,ref2013-d102312a . The AEO 2013 projection period is from 2013 to 2040. Since our investment period goes until 2042, we predicted natural gas prices for 2041 and 2042 based on the annual rate increase from 2030 to 2040 for the corresponding AEO 2013 side cases.

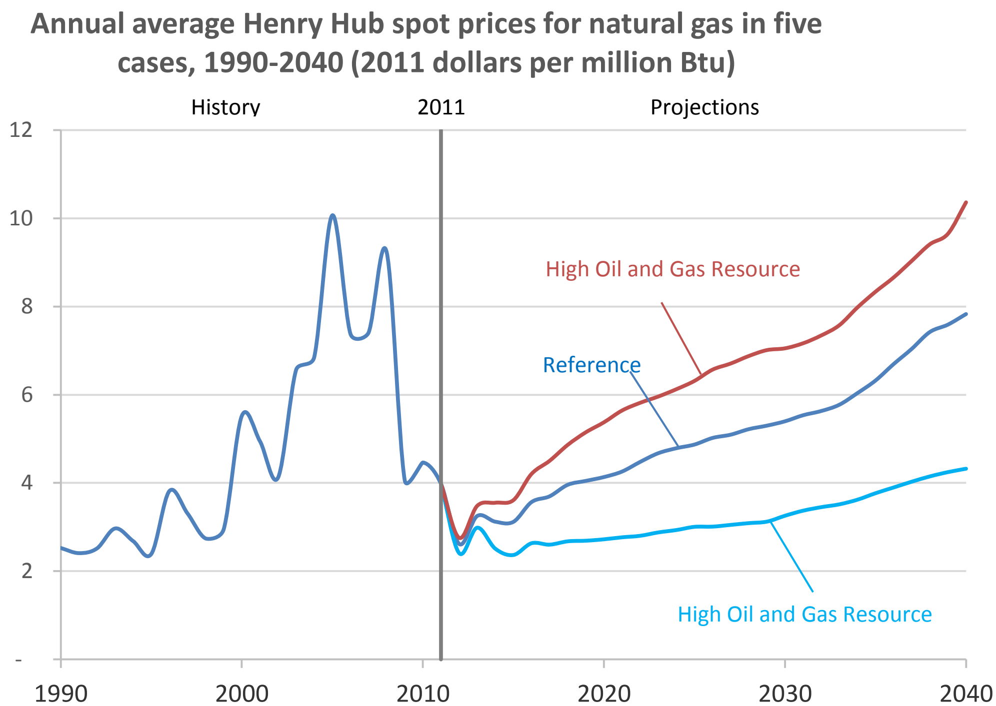

Figure 8. Henry Hub spot prices for AEO2013 reference and side cases[66]
Source: EIA

For the three carbon tax scenarios, we base annual gas prices on the AEO 2013 GHG10, GHG15, and GHG25 projections for the national average delivered price to the electric sector. The EIA assumes three different values for a carbon tax: $10, $15, and $25 per metric ton of CO_2, and assumes that the tax is enacted in 2015 with an annual increase of 5%.[67]

Decision Criteria Analysis

In scenario analysis, we calculate NPV cost points for each investment option outcome. When the least cost option varies across scenarios, however, investors and regulators can use other metrics such as modern economic decision criteria to evaluate options under uncertainty.[68] We use three criteria—maximax, maximin, and minimax regret—to evaluate the six investment options.

66 EIA, *Annual Energy Outlook 2013*.
67 EIA, *Annual Energy Outlook 2013*, 89.
68 David Pearce, *The MIT Dictionary of Modern Economics,*. MIT Press (2007).

- Using the maximax criterion, the investor would choose the least cost NPV option regardless of the probability of each scenario occurring. This criterion is suitable for the optimistic decision maker who believes that natural gas prices will stay low as the domestic gas supply grows.
- Using the maximin criterion, the investor is pessimistic about natural gas futures and assumes that the worst case scenario, the $25 carbon tax scenario, will occur. This criterion is suitable for conservative decision makers who believe stricter environmental regulations will significantly raise costs in the future.
- Using the minimax regret criterion, the investor assumes that a suboptimal option will be chosen, and tries to minimize the difference between that option's NPV cost and the minimum NPV cost for that scenario. The investor will minimize the difference or "regret" across all scenarios. This criterion is suitable for the conservative decision maker who wants to minimize potential losses from limited natural gas resources and emissions regulations.

Alternatives to Scenario Analysis

In addition to conducting scenario analysis using the EIA projections, we use Monte Carlo and Random Walk simulation to generate our own scenarios on natural gas price futures (Table 3). By using these methods, investors and regulators can better assess risk by comparing the NPV cost distributions of each option instead of the NPV point estimates.

Table 3. Additional scenarios generated using Monte Carlo and Random Walk Simulations

<table>
<tr><th></th><th>Scenario Name</th><th>Scenario Assumptions</th></tr>
<tr><td rowspan="3">Monte Carlo Simulation</td><td>Average Volatility Case</td><td>Lognormal distribution with average volatility</td></tr>
<tr><td>Low Volatility Case</td><td>Lognormal distribution with low volatility</td></tr>
<tr><td>High Volatility Case</td><td>Lognormal distribution with high volatility</td></tr>
<tr><td rowspan="4">Random Walk Simulation[69]</td><td>Random Walk without Drift Case</td><td>Takes a random step without any annual trend</td></tr>
<tr><td>Random Walk with Reference Increase Rate Case</td><td>Uses annual increase rate from the AEO 2013 Reference Case</td></tr>
<tr><td>Random Walk with Low Increase Rate Case</td><td>Uses annual increase rate from the AEO 2013 High EUR Case</td></tr>
<tr><td>Random Walk with High Increase Rate Case</td><td>Uses annual increase rate from the AEO 2013 Low EUR Case</td></tr>
</table>

[69] Bob Nau, "Forecasting: The Random Walk Model," (2013).

Monte Carlo Simulation for Natural Gas Prices

Monte Carlo analysis is "a stochastic modeling technique for estimating outcomes that are dependent on uncertain variables through repeated modeling runs."[70] Unlike traditional scenario analysis in which each scenario has a fixed bundle of cost assumptions, Monte Carlo analysis introduces probability distributions for the input variables. To conduct Monte Carlo simulation for the natural gas price inputs, we analyzed historical gas prices, which followed a lognormal distribution from 2002 to 2013 (Figure 9).

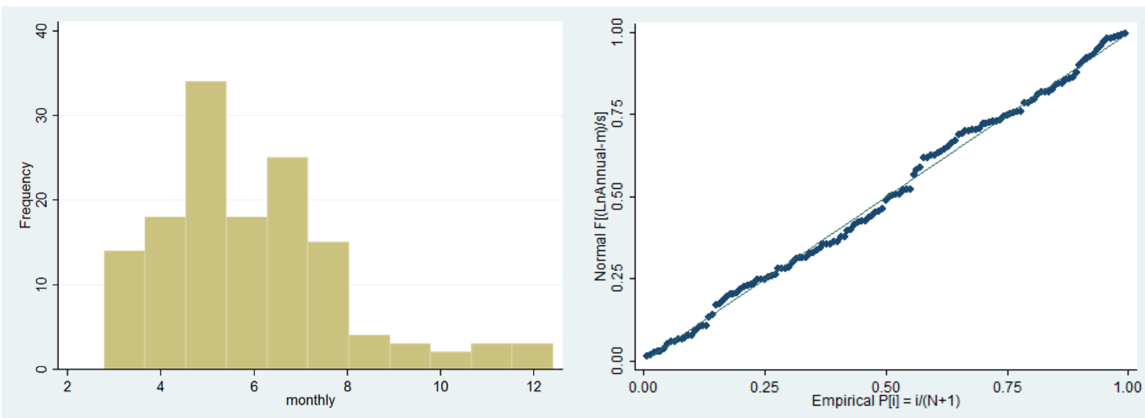

Figure 9. Statistical analysis for historical natural gas prices. On the right is the normal probability plot for logged natural gas prices, which shows that the monthly price fits a normal distribution after taking the logarithm.

For each year from 2013 to 2042, we assume that the annual natural gas price is also subject to a lognormal distribution with a mean value equal to the AEO 2013 reference case's projection for gas prices during the same year (see Figure 10 as an example). Thus our 30-year investment includes 30 different lognormal distributions for each year's natural gas price. For each model run, the gas price is randomly selected from each distribution. By running the model a hundred times, we create a distribution of outcomes that represent the uncertain future. As shown in Table 3, we also varied the standard deviation for the gas price distributions in the average, low, and high volatility cases. In the average volatility case, we use the historical average and assume a fixed wind PPA price of $55/MWh. In the low volatility and high volatility cases, we use low volatility and high volatility respectively to depict different natural gas price trends.

[70] Hoppock, Patino-Echeverri, and Adair, *Assessing the Risk of Utility Investments*.

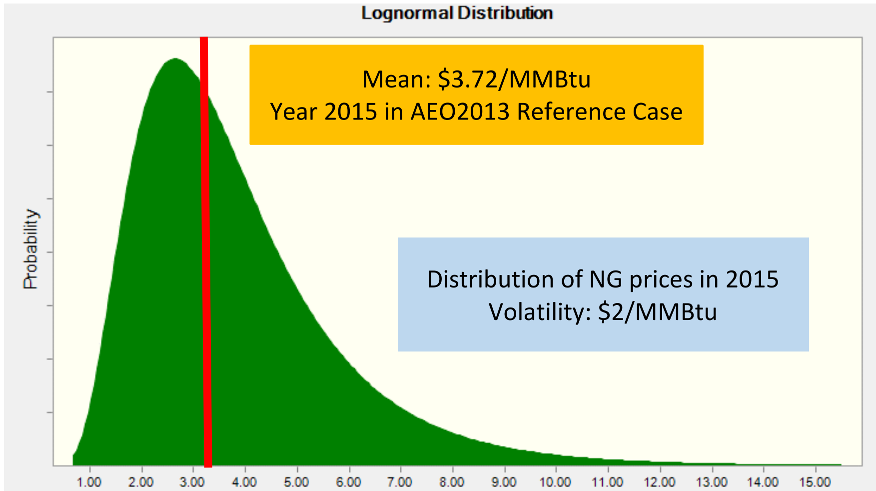

Figure 10. Lognormal distribution for natural gas prices in 2015 in the Average Gas Price Volatility Case

Random Walk Simulation

The random walk model is one of the most important models in time series forecasting that shows the unpredictability of the rate of return for the stock market.[71] In our analysis, natural gas can be viewed as a stock since its price will either go up or down in the future. As shown in the equation below, this model assumes that in each period, the natural gas price takes a random step away from its previous value, and that the steps are independently and identically distributed in size:

$$\ln(Y_{i,t}) = \alpha + \ln(Y_{i,t-1}) + \varepsilon_t$$
$$\varepsilon_t \sim iid\ N(drift, \sigma^2)$$

$Y_{i,t}$*: Natural gas price at time t;* ε_t*: Randomness*

A random walk model is said to have "drift" or "no drift" according to whether the distribution of step sizes has a non-zero mean or a zero mean. In the Random Walk without Drift Case, we assume that there is no annual increase rate for gas prices, while in the Random Walk with Drift Case, we use the annual increase rates from the AEO2013 reference case, low natural gas price (High EUR) case, and high gas price (Low EUR) case respectively.

Sensitivity Analysis

We also conducted sensitivity analysis for wind PPA prices and carbon tax prices to determine how these variables affect the hedging value of wind. By knowing what range of values will change the

[71] Nau, "Forecasting: The Random Walk Model."

investment outcomes, regulators can incorporate risk analysis into the least-cost decision framework.

Results

Scenario Analysis for Least-Cost Options

We found that in the EIA reference and low natural gas price case, the most cost-effective investment is NG 100%, where the utility would use gas generation only, while in the high gas price case, the least-cost investment is NG 0%, where the utility would meet demand with all wind generation (Figure 11). If the utility assumes that the low gas price scenario will occur and picks the NG 100% option over the 0% option when instead the high price scenario occurs, their NPV costs will increase by $600 million.

If a carbon tax of $10 per ton or more is enacted, the EIA predicts that natural gas-fired generation across the U.S. will increase sharply in 2015, and as shown in Figure 11, it would be least-cost to meet demand with wind PPAs only based on wind's carbon neutral attribute. Table 4 shows the least-cost option for the six EIA scenarios where the investor will either choose the NGCC plant or wind only depending on the scenario.

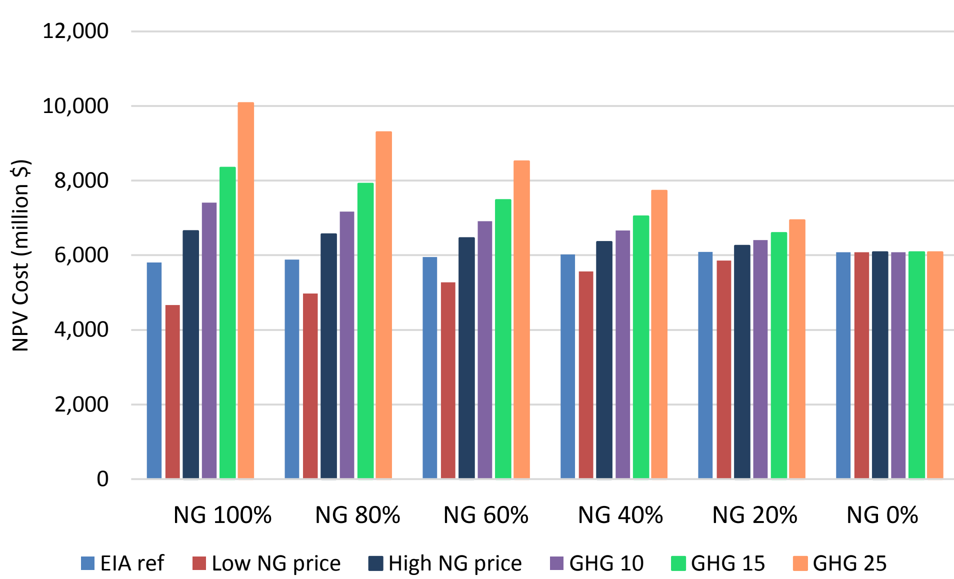

Figure 11. Net present value of costs for the six investment options across the EIA scenarios

Table 4. Least-cost options for EIA natural gas price scenarios (in million $)

	Reference	Low NG Price	High NG Price	GHG $10	GHG $15	GHG $25
NG 100%	$5,803	$4,666	$6,646	$7,407	$8,344	$10,073
NG 80%	$5,882	$4,972	$6,557	$7,166	$7,915	$9,298
NG 60%	$5,954	$5,272	$6,460	$6,916	$7,478	$8,515
NG 40%	$6,022	$5,567	$6,359	$6,663	$7,038	$7,729
NG 20%	$6,085	$5,858	$6,254	$6,406	$6,593	$6,939
NG 0%	$6,080	$6,080	$6,080	$6,080	$6,080	$6,080

For our scenario analysis, we choose the option that minimizes the NPV cost without considering the risk profile. We can get an idea of the risk profile, however, by looking at the spread of results for each investment option across the six EIA scenarios. Figure 12 shows the cost bands for the six options, and the red vertical lines represent the NPV cost in EIA reference case, which can be viewed as the base case. While NG 100% is least cost in the base case, the worst possible outcome for NG 100% is much larger than for the other options.

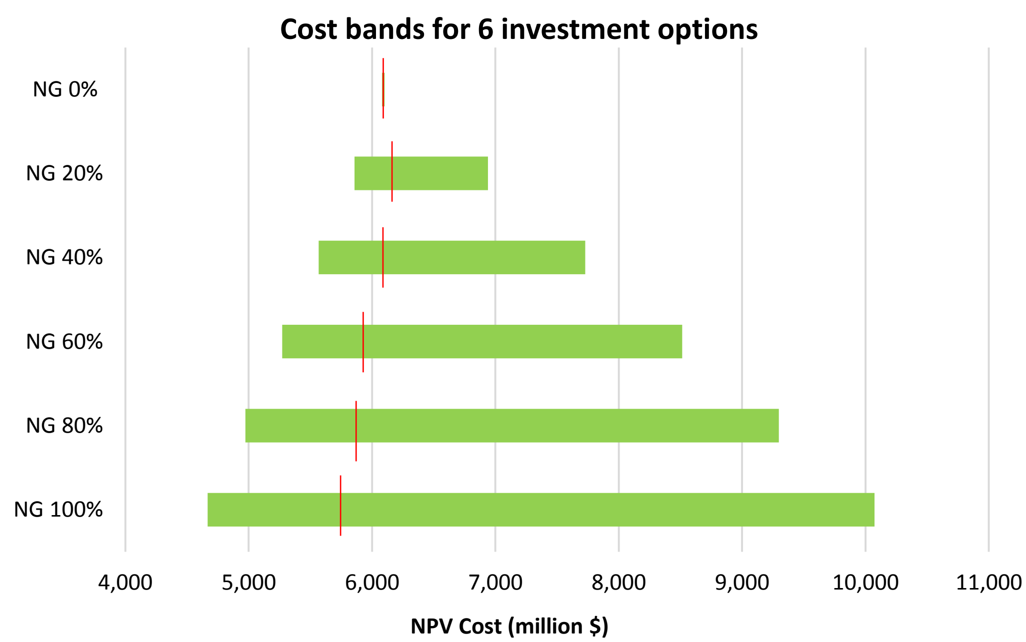

Figure 12. Net present value cost bands for the six investment options across the EIA scenarios

Decision Criteria Analysis

Table 5 to Table 7 show the optimal results based on three criteria: maximax, maximin, and minimax regret.

- Using the maximax criterion, the investor would pick NG 100% with a lowest possible NPV cost of $4,666 million. The investor believes that the high oil and gas resource case will occur and fuel costs will remain low.
- Using the maximin criterion, the investor would choose NG 0%, which has the lowest NPV cost out of all the maximum costs. The investor is concerned that stricter environmental regulations will significantly raise costs in the future.
- Using the minimax regret criterion, the investor will minimize the difference or "regret" across all scenarios and choose the NG 20% option, which includes 80% wind generation.[72] In this case, the investor wants to minimize potential losses from limited natural gas resources and emissions regulations in the future.

Table 5. Maximax Criterion Matrix

	Reference	Low NG Price	High NG Price	GHG $10	GHG $15	GHG $25	Min Cost
NG 100%	$5,803	$4,666	$6,646	$7,407	$8,344	$10,073	**$4,666**
NG 80%	$5,882	$4,972	$6,557	$7,166	$7,915	$9,298	$4,972
NG 60%	$5,954	$5,272	$6,460	$6,916	$7,478	$8,515	$5,272
NG 40%	$6,022	$5,567	$6,359	$6,663	$7,038	$7,729	$5,567
NG 20%	$6,085	$5,858	$6,254	$6,406	$6,593	$6,939	$5,858
NG 0%	$6,080	$6,080	$6,080	$6,080	$6,080	$6,080	$6,080

[72] We create a "regret" matrix by finding the difference between the optimal NPV for each scenario (least-cost option in Table 5) and the other investment options. For example, in the EIA reference or the base case, the regret for the NG 80% option is equal to its own NPV cost, $5,882 million, minus the least-cost option in this scenario, which is $5,803 million.

Table 6. Maximin Criterion Matrix

	Reference	Low NG Price	High NG Price	GHG $10	GHG $15	GHG $25	Max Cost
NG 100%	$5,803	$4,666	$6,646	$7,407	$8,344	$10,073	$10,073
NG 80%	$5,882	$4,972	$6,557	$7,166	$7,915	$9,298	$9,298
NG 60%	$5,954	$5,272	$6,460	$6,916	$7,478	$8,515	$8,515
NG 40%	$6,022	$5,567	$6,359	$6,663	$7,038	$7,729	$7,729
NG 20%	$6,085	$5,858	$6,254	$6,406	$6,593	$6,939	$6,939
NG 0%	$6,080	$6,080	$6,080	$6,080	$6,080	$6,080	**$6,080**

Table 7. Minimax Regret Criterion Matrix

	Reference	Low NG Price	High NG Price	GHG $10	GHG $15	GHG $25	Regret
NG 100%	$0	$0	$566	$1,327	$2,263	$3,992	$3,992
NG 80%	$79	$306	$477	$1,085	$1,834	$3,218	$3,218
NG 60%	$150	$605	$379	$836	$1,398	$2,435	$2,435
NG 40%	$218	$901	$279	$583	$957	$1,649	$1,649
NG 20%	$282	$1,192	$174	$326	$513	$859	**$1,192**
NG 0%	$277	$1,414	$0	$0	$0	$0	$1,414

Alternatives to Scenario Analysis: Net Present Value Cost Distributions

Monte Carlo Simulation

The cost distributions for the six investment options across the Monte Carlo scenarios are shown in Figure 13 to Figure 15, where we use box plots to compare their median, maximum, minimum, and percentile information. Although the median value for each option is similar in each scenario, the length of the box (90th percentile minus the 10th percentile) varies considerably and decreases from the NG 100% to NG 20% option with less reliance on gas generation. In the NG 0% option, the cost becomes a point estimate since future demand is all met with wind energy. The length of the box also varies by scenario; for the high volatility case (Figure 15), the range of costs for each option is greater than in the average volatility case (Figure 13).

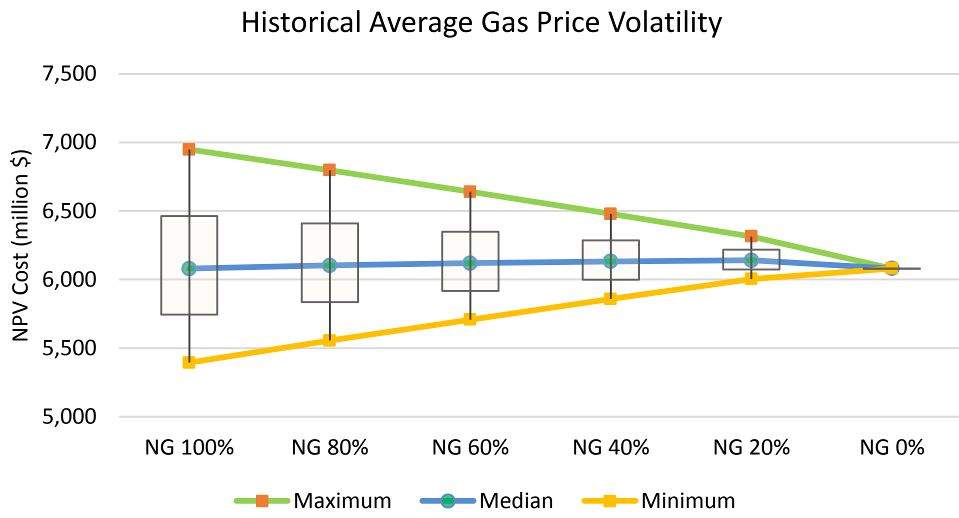

Figure 13. Cost plots for the six investment options under historical average gas price volatility scenario

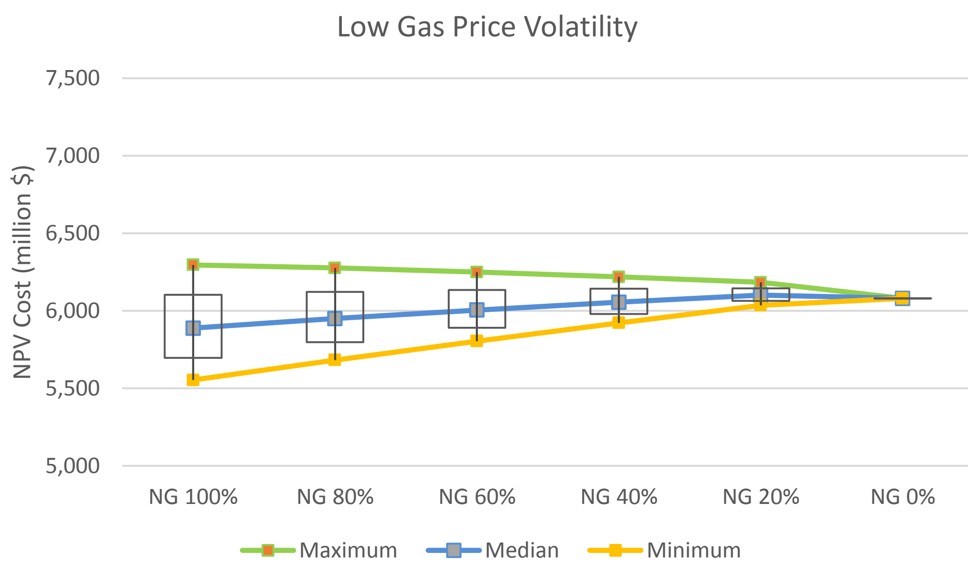

Figure 14. Cost plots for the six investment options under low gas price volatility scenario

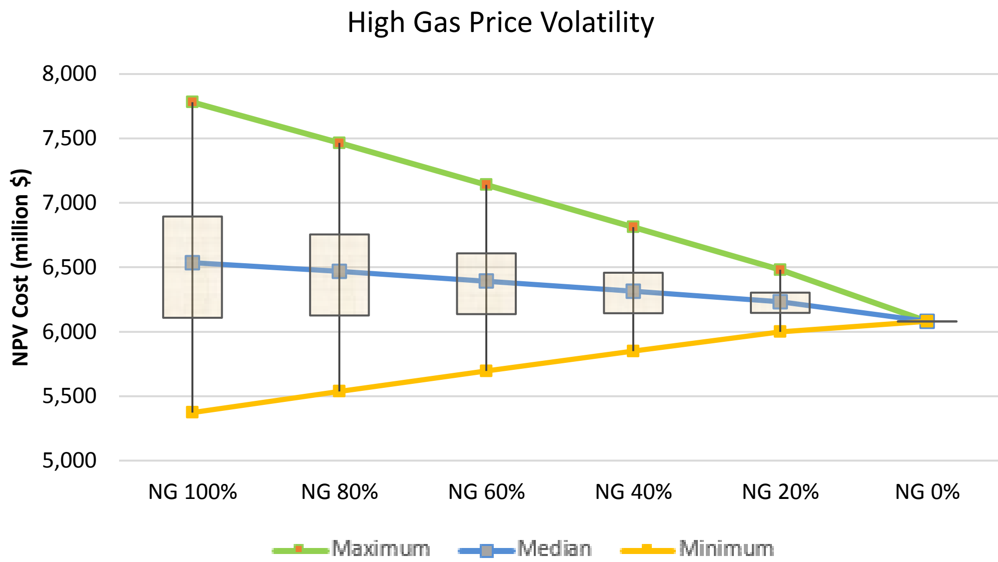

Figure 15. Cost plots for the six investment options under high gas price volatility scenario

A good example of how to quantify the hedging value of wind against natural gas price volatility is displayed in Figure 16, where the NG 100%, NG 80%, and NG 60% option cost distributions are shown. Although the median value of costs for the NG 60% option ($5.9 billion) is larger than that of the 100% option ($5.8 billion), the 90% confidence interval for the NG 60% option ($5.7 billion to $6.2 billion) is narrower than the interval for the NG 100% option ($5.4 billion to $8.2 billion). According to these results, if utilities rely on gas generation alone, their total NPV costs could increase significantly in the event of an unfavorable future.

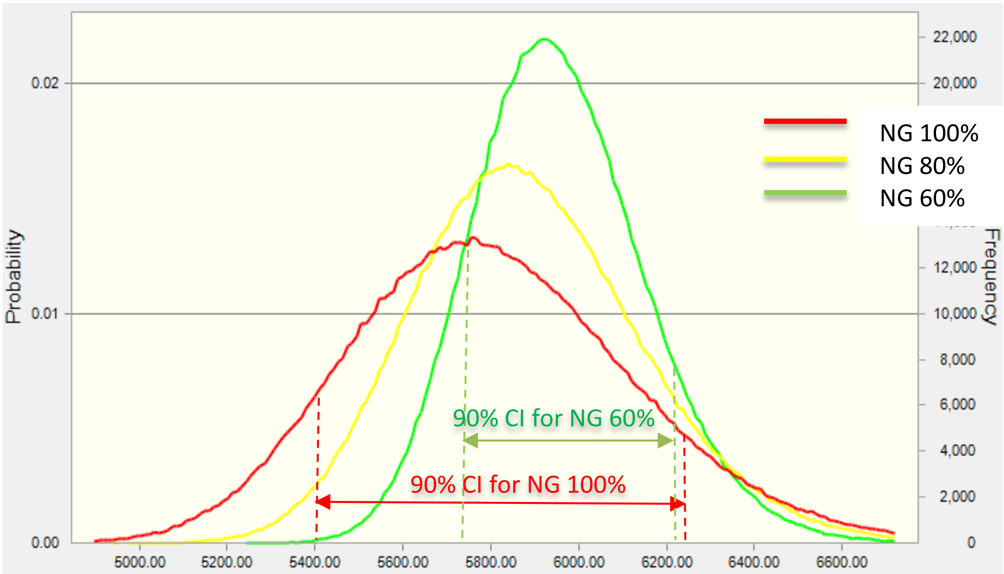

Figure 16. Probability distribution of costs for NG 100%, 80%, and 60% options under the average gas price volatility scenario

Random Walk Simulation

The NPV cost distributions for the six investment options with no annual increase for gas prices are shown in Figure 17. Although the median value of the NG 0% option costs ($6.0 billion) is larger than that of the NG 100% option costs ($4.8 billion), the 90% confidence interval for NG 100% option is $3.5 billion to $7.6 billion, whereas there is no interval for the NG 0% option since the utility does not need to consider natural gas price risk if they rely on wind energy from fixed PPAs.

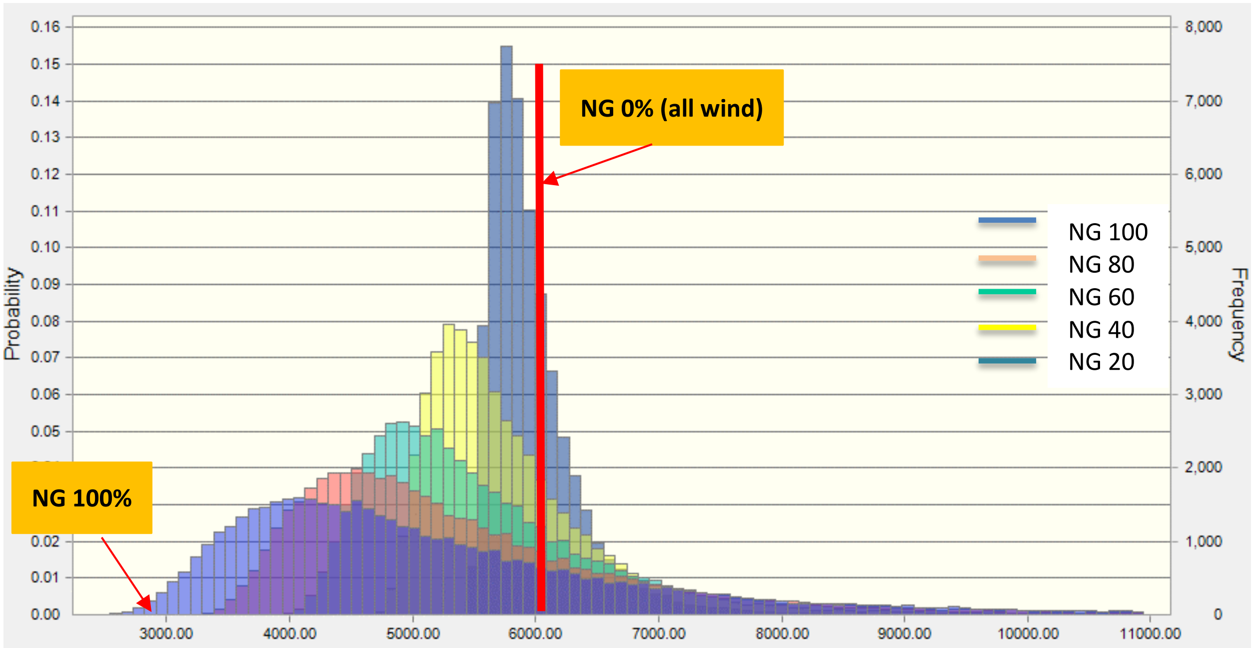

Figure 17. NPV cost probability distributions for the six options assuming there is no annual increase in the gas price

In Random Walk with Drift Cases, Figure 18 shows the NPV cost distribution for the NG 100% option across different drift assumptions. As the annual increase rate grows, utilities are increasingly exposed to more high cost outcomes. For the low annual increase rate scenario based on the EIA low natural gas price case, the 90% confidence interval is $3.5 billion to $7.7 billion; under the high increase rate scenario from the high gas price case, the 90% confidence interval is $4.0 billion to $10.3 billion.

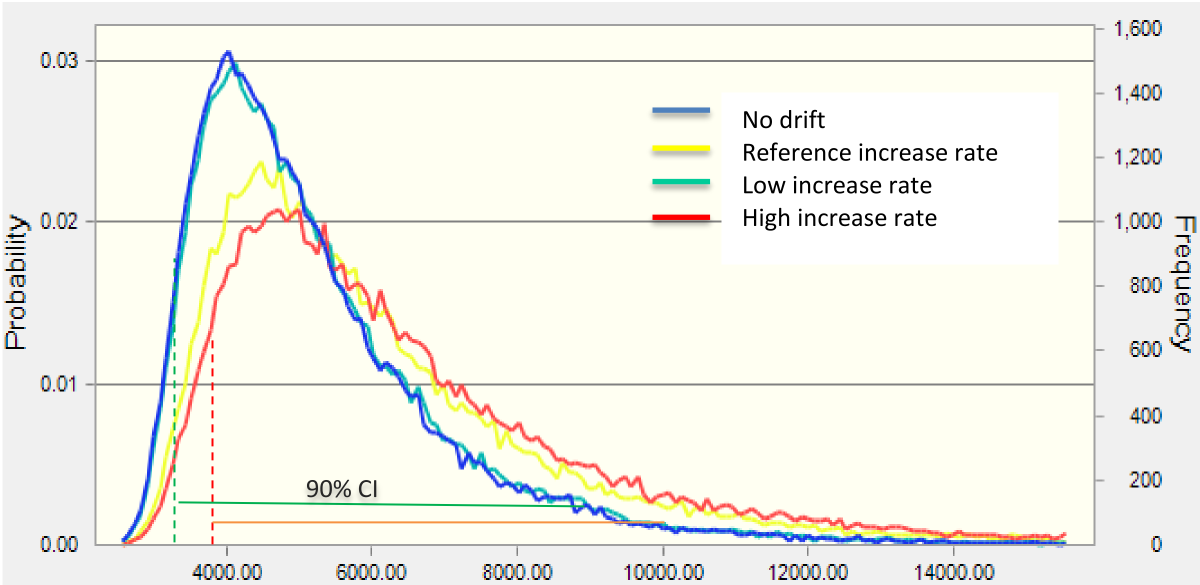

Figure 18. NPV Cost probability distribution for the NG 100% option under no drift scenario (no annual increase rate for natural gas price), reference, low, and high annual increase rate scenarios based on assumptions from the EIA reference, High EUR and Low EUR cases.

Sensitivity Analysis

One-Factor Analysis: Wind Power Purchase Agreement Prices

In 2012, the national average PPA price was \$40/MWh, making wind competitive with other types of generation in the wholesale electricity market.[73] With the expiration of the PTC in 2013 however, the EIA projects that the average PPA price will be \$86.6/MWh in 2018.[74] Using this price in the EIA reference case, utilities will choose the NG 100% option under the least-cost framework. If we decrease the PPA price, however, the NPV costs for the options with wind energy will decline and the least cost outcome will change accordingly. Figure 19 to Figure **21** show the NPV costs for the six investment options in the reference, low natural gas price, and high price cases when we change the PPA price from \$40/MWh to \$86.6/MWh.[75] In the low gas price case, PPA prices need to reach below \$41/MWh for wind energy to become economically competitive with gas, while in the high gas price case, wind could still have an advantage in the market with PPA prices of up to \$59/MWh.

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[73]Bolinger and Wiser, *2012 Wind Technologies Market Report*.
[74] In the *Wind Technologies Market Report*, the PPA prices do not include wind integration and transmission costs, but they do include the PTC at 2.3 cents/kWh. The EIA's PPA price includes a transmission investment cost of \$3.2/MWh and assumes the PTC will not be renewed after 2013.
[75] We use the 2012 national average PPA price of \$40/MWh as our lower bound for the price analysis (Bolinger and Wiser, 2012 Wind Technologies Market Report 2013).

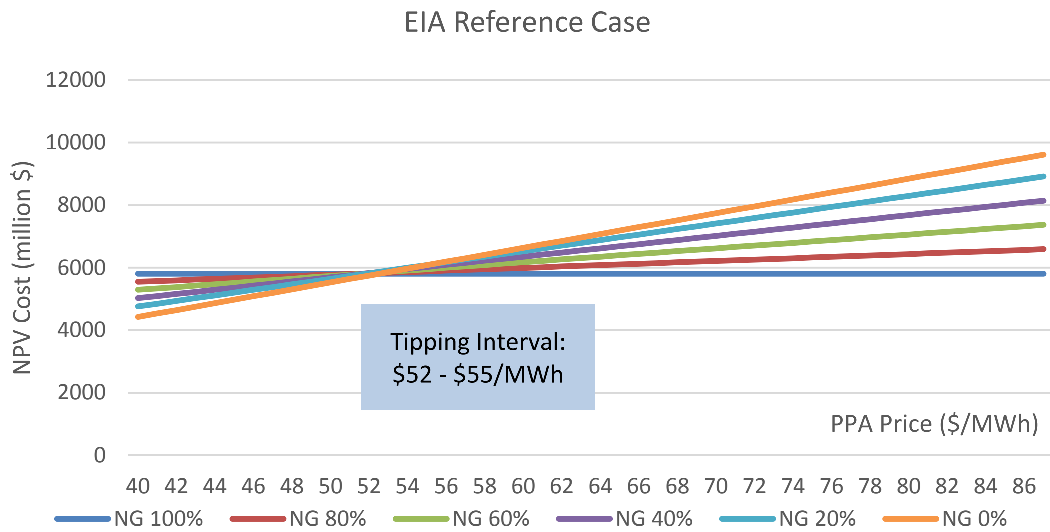


Figure 19. Sensitivity analysis to determine the PPA price interval below which NG 0% option becomes most cost-effective (wind energy dominant) in the EIA reference case

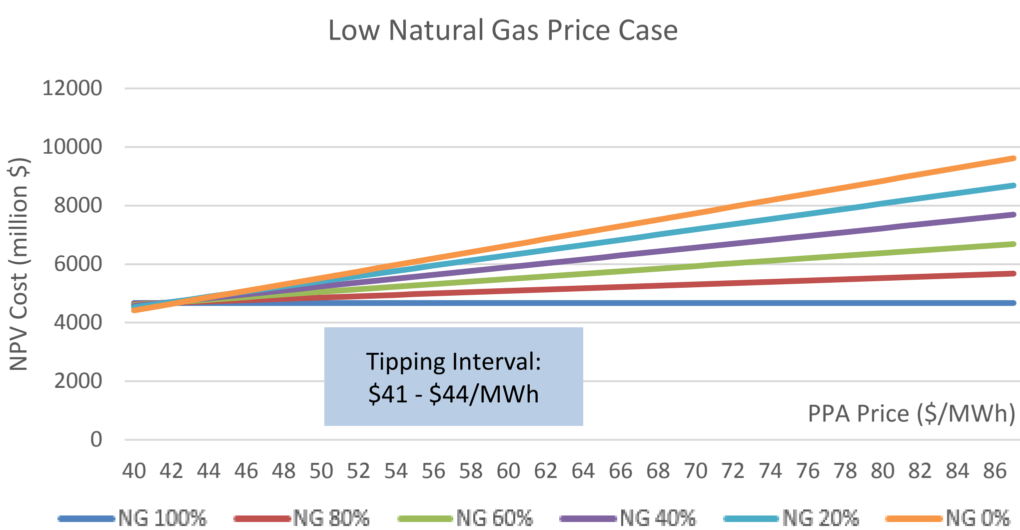


Figure 20. Sensitivity analysis to determine the PPA price interval below which NG 0% option becomes most cost-effective in the EIA low natural gas price case

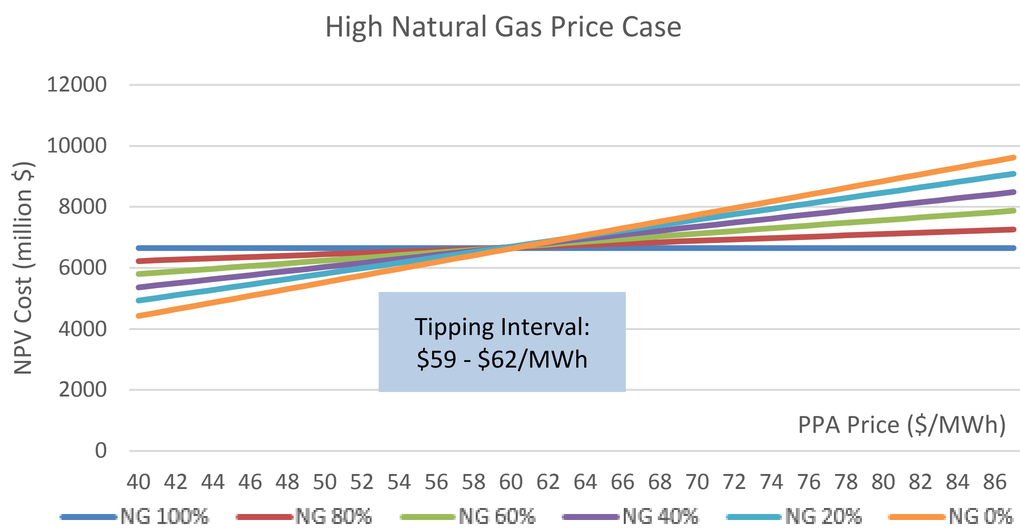


Figure 21. Sensitivity analysis to determine the PPA price interval below which the NG 0% option becomes most cost-effective in the EIA high gas price case

For the Monte Carlo gas price scenarios, changing the wind PPA price will lead to different NPV cost distributions. The tipping range of PPA prices for the average volatility scenario is $52.0 to $58.5/MWh. If the actual wind PPA price falls below this range, the PUC should approve more wind energy based on the transmission capacity since the NG 0% option cost is below the NG 100% option's 10th percentile cost value (Figure 22), meaning that NG 0% has at least a 90% probability of being lower cost than NG 100%. If the PPA price is higher than $58.5/MWh however, natural gas fired generation will be least cost since the NG 0% NPV cost is greater than the NG 100% option's 90th percentile cost value. The tipping ranges of PPA price for the low volatility and high volatility scenarios are $51.5 to $55.2/MWh and $55.3 to $62.4/MWh respectively. Although the median value of NPV costs for the options with wind would increase if PPA prices were to increase, wind energy can still be used to hedge against risk by narrowing the potential cost distribution.

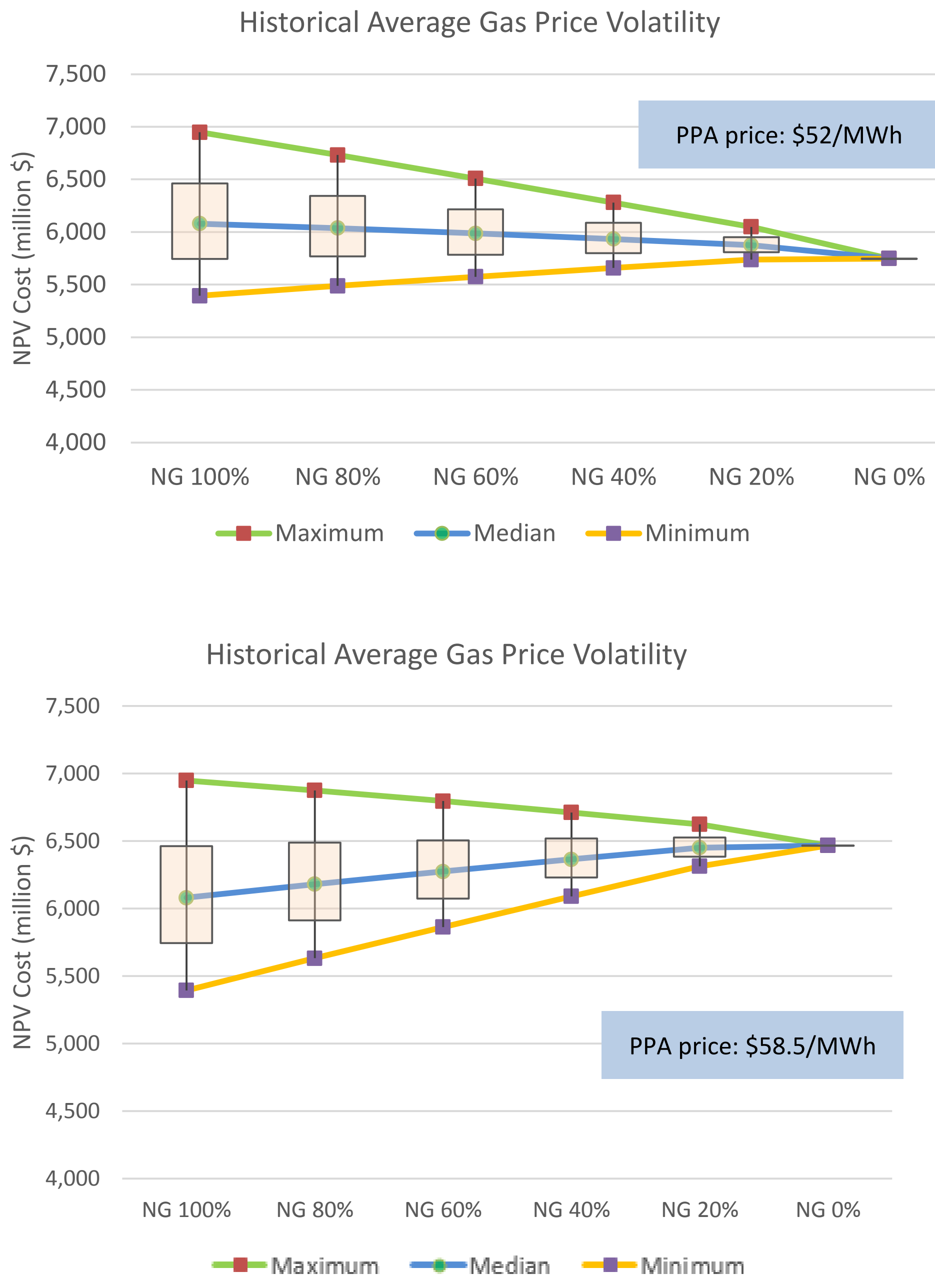
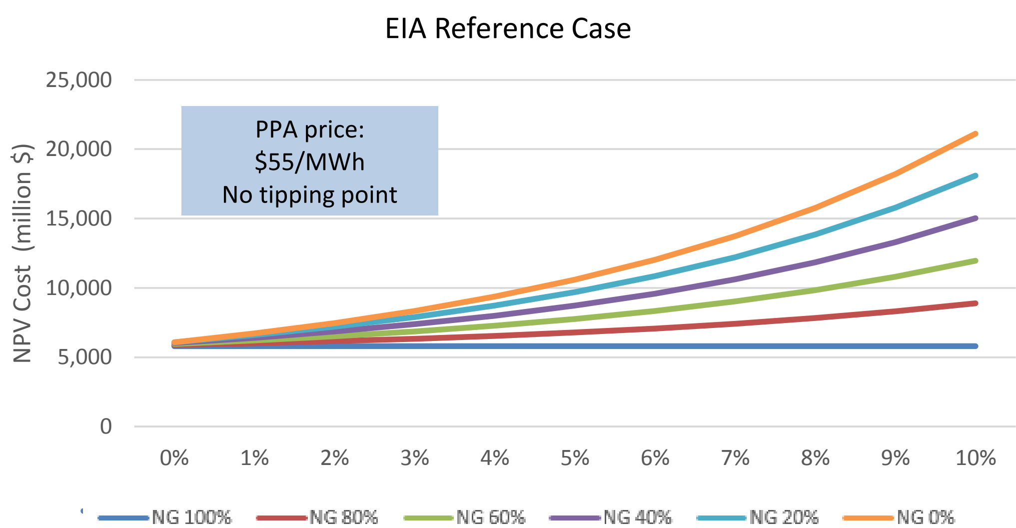


Figure 22. Box plots for the six investment options using high and low PPA prices under the historical average gas price volatility scenario

Wind PPA Prices with Annual Increase Rates

We also conducted a sensitivity analysis on different types of wind PPAs to evaluate how different purchase terms affect the investment outcome. In the LBNL wind PPA sample, 59% of the prices remain fixed in nominal dollars over the entire agreement period, which is what we assumed in our scenario analysis, while 38% of the PPA prices increase each year at an average rate of 2.4%.[76] While including this annual increase would result in larger NPV costs for the options with wind, the starting point for the wind PPA price is crucial in determining whether wind can be economically competitive. Assuming that the PPA escalates, we find that there is no tipping point for the annual increase rate in the EIA reference case using the original $55/MWh price (Figure 23). If the starting point is fixed at the 2012 national average price $40/MWh, however, there is a tipping point at 2.7%.



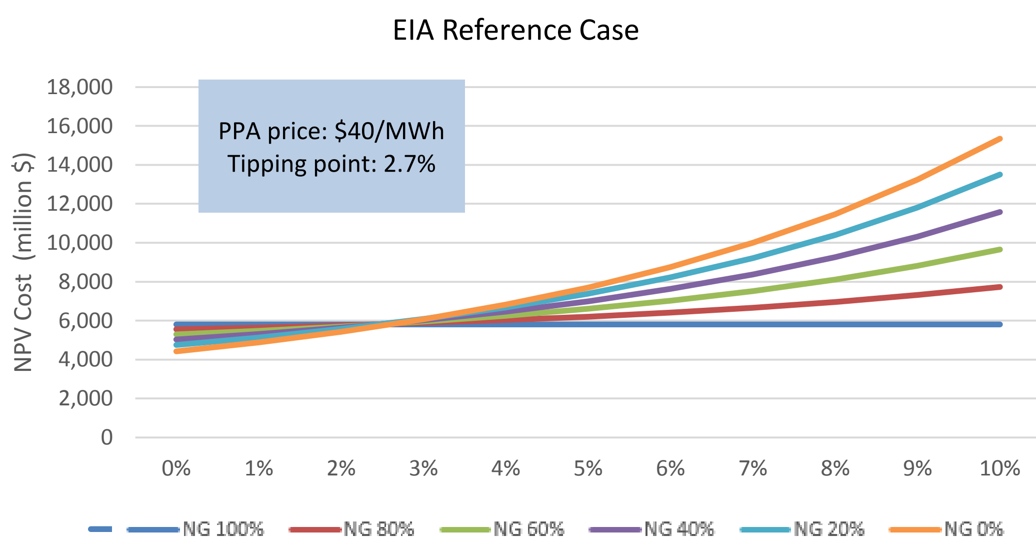


Figure 23. Sensitivity analysis for the annual increase rate of escalating PPAs in the EIA reference case

[76] Bolinger, *Long-Term Hedge Value of Wind*.

Two-Factor Analysis: Wind PPA Prices versus Carbon Tax Prices

When two variables such as the PPA price and carbon tax price both influence the NPV cost outcomes, a color-based heat map (see Table 8 and Table 9) can be used to show which variable affects the outcome more (smaller values are shaded green while larger values are in red). As shown in the heat maps, the NG 80% option cost is more sensitive to the carbon tax price since the vertical color change is more significant, while the NG 20% option cost is more sensitive to the PPA price.

Table 8. Heat map of NPV costs for the NG 80% option under EIA reference and carbon tax scenarios (in million $)

PPA Price ($/MWh)	40	45	50	55	60	65	70	75	80	85
Reference	$5,496	$5,607	$5,717	$5,828	$5,938	$6,048	$6,159	$6,269	$6,380	$6,490
GHG $10/t CO2	$6,766	$6,877	$6,987	$7,098	$7,208	$7,318	$7,429	$7,539	$7,650	$7,760
GHG $15/t CO2	$7,508	$7,618	$7,729	$7,839	$7,950	$8,060	$8,171	$8,281	$8,392	$8,502
GHG $25/t CO2	$8,879	$8,989	$9,100	$9,210	$9,321	$9,431	$9,541	$9,652	$9,762	$9,873

Table 9. Heat map for of NPV costs for the NG 20% option under EIA reference and carbon tax scenarios (in million $)

PPA Price ($/MWh)	40	45	50	55	60	65	70	75	80	85
Reference	$4,999	$5,331	$5,663	$5,994	$6,326	$6,658	$6,989	$7,321	$7,653	$7,984
GHG $10/t CO2	$5,634	$5,966	$6,298	$6,629	$6,961	$7,293	$7,624	$7,956	$8,288	$8,619
GHG $15/t CO2	$6,005	$6,337	$6,668	$7,000	$7,332	$7,663	$7,995	$8,327	$8,658	$8,990
GHG $25/t CO2	$6,690	$7,022	$7,354	$7,685	$8,017	$8,349	$8,680	$9,012	$9,344	$9,675

Model Limitations

While our analysis provides quantitative results to guide decision, there are a number of limitations to this analysis. First, we are only able to model a single investment decision to meet future demand, whereas utilities make investment decisions based on their supply side generation portfolios and demand side resource plans. Second, while our model chooses an investment option that is executed in year 1, in reality a utility can invest in stages. For example, a utility could start building a large NGCC plant while gas prices are low, then gradually add wind PPAs to its portfolio and decrease the capacity factor of the NGCC plant if natural gas prices spike in the future.

Southeast Case Study

We apply our investment decision model to electric utilities in the Southeast, where they are traditionally regulated by state commissions. The utilities are also vertically integrated, meaning they own the generation capacity as well as the transmission and distribution systems, and they have a natural monopoly on the supply of electricity. We also focus on the Southeast since no states in the region have renewable portfolio standards or goals except for North Carolina.[77] Although there are wind resources in the Southeast,[78] there are currently no wind installations except in Tennessee, where the Tennessee Valley Authority (TVA) owns a 27 MW wind farm near Oak Ridge.[79]

In particular, we analyze the wind purchases made by Southern Company, an investor-owned utility, and TVA, a government-owned utility. Southern Company serves 4.4 million customers in Georgia, Alabama, and parts of Mississippi and Florida,[80] while TVA serves over 9 million customers in a seven-state region (Figure 24).[81] Southern Company is known for providing electricity at rates below the national average, and has been traditionally resistant to importing electricity from outside their service territory.[82] In recent years, however, both utilities have worked to reduce their exposure to fuel cost risk by investing in renewables and nuclear although neither utility's resource planning is being driven by RPS. Southern Company is the first to commence nuclear construction in the U.S. in the past 30 years, and has just received $6.5 billion in federal loan guarantees to build two new nuclear reactors in Georgia.[83]

[77] Database of State Incentives, *Rules, Regulations & Policies for Renewable Energy.*
[78] Bolinger and Wiser, *2012 Wind Technologies Market Report*. The average capacity factor for wind in the Southeast is 23% compared to 36% in the Interior,
[79] Tennessee Valley Authority, *Energy Purchases from Wind Farms,* 2013, accessed February 14, 2014, https://www.tva.com/power/wind_purchases.htm.
[80] Southern Company, *Investor Fact Sheet,* accessed February 25, 2014, http://investor.southerncompany.com/factsheet.cfm.
[81] Tennessee Valley Authority, *About TVA,* accessed March 3, 2014, http://www.tva.com/abouttva/.
[82] Daniel Cusick, *Georgia Power to bring wind onto grid,* April 23, 2013, accessed February 10, 2014, http://www.eenews.net/climatewire/stories/1059979898/.
[83] Hannah Northey, *E&E News: "DOE to close historic $6.5B loan guarantee for Ga. reactors tomorrow,"* February 19, 2014, accessed February 19, 2014, http://www.eenews.net/eenewspm/stories/1059994810/.

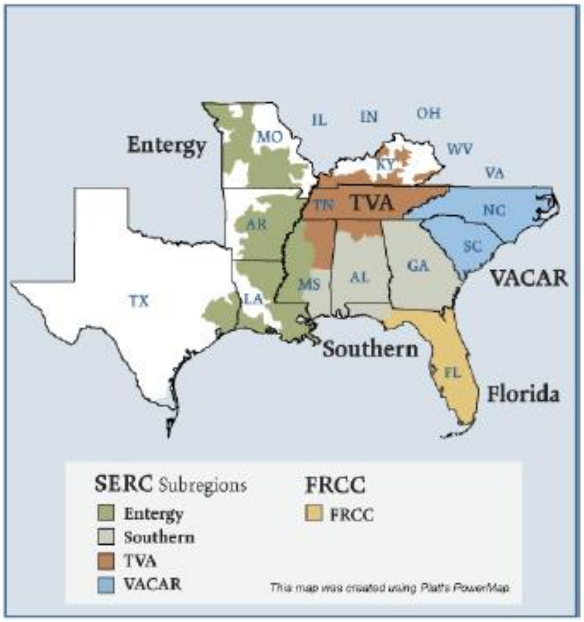


Figure 24. Southeast Electric Reliability Council (SERC) Subregions[84]
Source: FERC

Southern Company has been adding renewable sources to its portfolio through power purchase agreements for biomass, solar, and wind.[85] In 2011, Alabama Power was its first subsidiary to buy wind, signing a 20-year, 202 MW contract with TradeWind Energy for wind power from Oklahoma beginning in December 2012. Alabama Power has stated that the PPA price is less than their avoided cost, and that the agreement will help them hedge against future regulations such as a federal renewable portfolio standard and gain experience with renewables without having to deal with the intermittency.[86] They will get the associated renewable energy credits, which they can retire or sell, in addition to selling the wind energy to others.[87] The wind farms will be delivered via a 345 kV transmission line held by Oklahoma Gas & Electric.[88] In 2012, Alabama Power also signed another agreement with TradeWind Energy for an additional 202 MW of wind from the Buffalo Dunes Wind Project in Kansas for delivery in 2014. The utility has said that these agreements "allow them to bring wind energy to our customers without burdening them with investment costs."[89]

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[84] Federal Energy Regulatory Commission, *Electric Power Markets: Southeast,* accessed February 14, 2014, http://www.ferc.gov/market-oversight/mkt-electric/southeast.asp.
[85] Platts, *Electric Power Daily,* September 8, 2011. www.platts.com.
[86] Platts, *Electric Power Daily,* September 8, 2011.
[87] Alabama Power, *Environmental News,* accessed February 15, 2014,
[88] Platts, *Electric Power Daily,* September 8, 2011.
[89] Alabama Power, *Environmental News,* accessed February 15, 2014,

Using our model and the EIA projections for delivered natural gas prices to the electric sector in the Southeast, we were able to confirm Alabama Power's investment in wind using their Oklahoma PPA price of $32.21/MWh (Figure 25). The agreement price is so low that the NG 0% or all wind option is always the least cost across the reference, low gas price and high gas price scenarios.

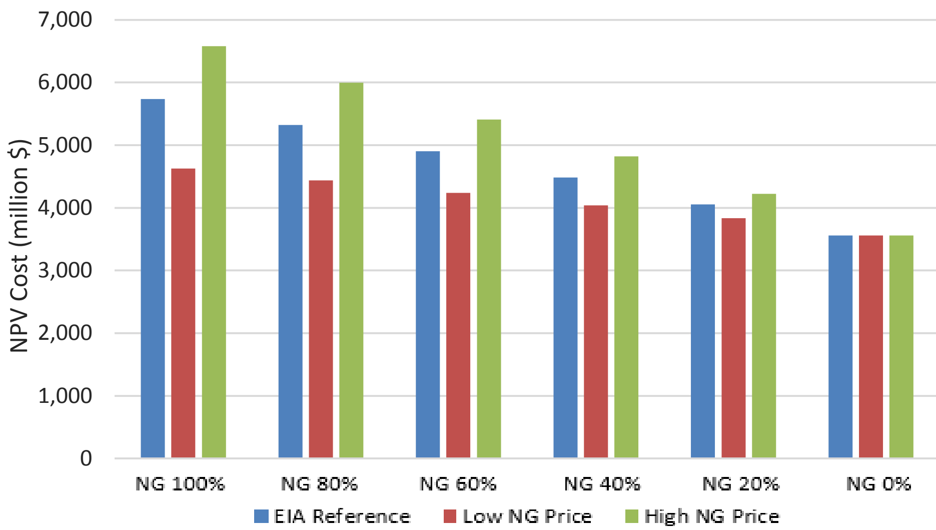

Figure 25. Net present value of costs for the 6 investment options using Alabama Power's wind PPA. At $32/MWh, the all-wind option is least-cost across all the natural gas price scenarios.

Wind prices – just too good of a deal for Georgia Power

Southern Company's Georgia subsidiary also provides a relevant case study since the state public service commission (PSC) has in effect mandated solar generation,[90] and their two new nuclear reactors are being built at the Vogtle plant in Georgia. Georgia Power's generation portfolio has been undergoing large shifts in recent years – in 2011, they generated 62% of their electricity from coal, while in 2012, 39% of their electricity was from coal, 33% from gas and oil, and 27% from nuclear.[91] Georgia Power is planning to retire 2,093 MW of coal and oil-fired generation due to the Mercury and Air Toxics Standards compliance required by April 2016 in combination with decreasing electricity demand and the low cost of natural gas.[92]

In 2013, Georgia Power applied for the PSC's approval for their two wind PPAs with EDP Renewables for 250 MW of wind energy from Oklahoma starting in 2016. The utility did not even

[90] Daniel Cusick, *E&E News: Ga. ruling to trigger rise in renewable energy,* July 12, 2013, accessed March 5, 2014, http://www.eenews.net/climatewire/stories/1059984294.
[91] Georgia Power, *Energy Sources,* accessed February 10, 2014, http://www.georgiapower.com/about-energy/energy-sources/home.cshtml.
[92] Georgia Power, "2013 Integrated Resource Plan," Docket No. 36498, 2013: 1-7.

go through the PSC's request for proposal process since the PPAs presented them with an "extraordinary advantage" in avoided energy costs.[93] The 20-year agreements benefit consumers by lowering baseload cost even with the annual increase rate included. Combined with solar, the wind PPAs increase Georgia Power's reserve margins and are not part of their Green Power Program. (Georgia Power does not mention the PPAs on their consumer-facing website.) The utility also owns the RECs associated with the wind generation, and has requested an additional $2.30 per kilowatt year of the nameplate capacity of Blue Canyon II and VI generating facilities as revenue for their shareholders.[94]

Although Georgia Power's PPA prices are confidential, we were able to estimate the price range using EIA projections for delivered gas prices to the electric sector in the Southeast, assuming that the utility uses similar price scenarios (Table 10). Under the reference case, we estimate the PPA price is in the range of $56 to $59/MWh, if not lower considering that Alabama Power was able to sign an agreement for $32/MWh for wind from Oklahoma.

Table 10. Wind power purchase agreement price ranges where wind is competitive with gas generation for the South Atlantic census region.

Intervals ($/MWh)	EIA Reference Case	$56-$59
	Low natural gas price case	$46-$49
	High natural gas price case	$64-$67

Tennessee Valley Authority's wind purchases

TVA is the ideal utility for our investment model since they are planning to build 900 to 9,300 MW of new gas-fired generation through 2029, which corresponds with the NG 100% option. TVA also currently has nine PPAs that total 1,352 MW in generation capacity, which is close to the amount of generation for the all-wind or NG 0% option.[95] Similar to Southern Company, TVA relies heavily on coal and nuclear generation,[96] although they have committed to generating 50 percent of its

[93] Georgia Power, "2013 Integrated Resource Plan," See Georgia PSC Commission Rule 515-3-4-.04(3)(f)(3).
[94] Georgia Power, "Georgia Power Company's Application for the Certification of the Power Purchase Agreements for Wind Resources from the Blue Canyon II and Blue Canyon VI Wind Farms," Docket No. 37854, 2013.
[95] TVA, *Energy Purchases from Wind Farms.*
[96] TVA, Notice of Intent, "Supplemental Environmental Impact Statement—Integrated Resource Plan," *Federal Register* 78, no. 211 (October 31, 2013): https://www.federalregister.gov/articles/2013/10/31/2013-25867/supplemental-environmental-impact-statement-integrated-resource-plan. In 2013, 41% of TVA's generation was from coal and 38% was from nuclear.

electricity from renewable sources by 2020.[97] Unlike other utilities in the Southeast, TVA owns an 18-turbine wind farm near Oak Ridge, Tennessee, and has been trying to develop wind energy in Alabama as well through the Shinbone Wind Project.[98]

TVA started signing wind PPAs in 2009, when the national average price of wind was relatively high at $67/MWh.[99] We were able to obtain five of TVA's PPA prices for wind energy from Kansas and Illinois, and found the average price to be $66.80/MWh (see Appendix). Using the EIA natural gas price and carbon tax price scenarios, we found that gas-fired generation is always least cost to meet demand for the reference, low gas price, and high gas price scenarios (Figure 26). Wind only becomes economically competitive when a carbon tax of $15 per ton is enacted in 2015, which indicates that TVA values wind's long-term hedging attributes over its near term costs. We find that TVA assumes a carbon tax of $17 per ton in almost all their scenarios in their 2011 Integrated Resource Plan, and confirm their strategy to hedge against future emissions regulation by adding more wind to their portfolio.

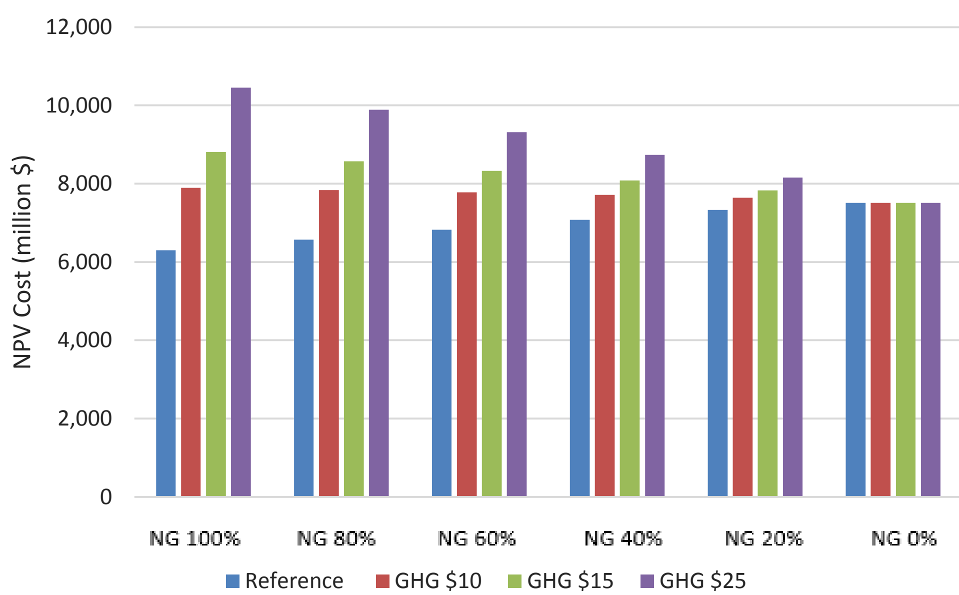

Figure 26. Net present value of costs for TVA's average wind PPA price across national carbon tax scenarios. Wind only becomes competitive with a $15 carbon tax.

[97] Daniel Cusick, *Big Southern utilities get renewable energy awards -- a departure from the past,* November 27, 2012, accessed February 2, 2014, http://www.eenews.net/climatewire/stories/1059972922.
[98] Cusick, *Big Southern utilities get renewable energy awards*.
[99] Bolinger and Wiser, *2012 Wind Technologies Market Report*, vii.

TVA is an example of a utility that has integrated risk assessment into their strategic planning. Using reliability as a constraint, TVA seeks to find the generation capacity mix that will "produce the minimum cost over their 20-year planning horizon," and wind PPAs fit into their strategy that is robust across scenarios.[100]

Conclusion

- **Utilities can avoid high cost outcomes from natural gas price spikes and stricter regulation by diversifying their portfolio with wind generation**

If utilities only invest in gas-fired generation, they will have increased exposure to fuel price volatility and potential environment regulations such as a carbon tax. Natural gas prices respond to the dynamics of demand and supply, which varies according to the volume and efficiency of drilling operations; the amount of recoverable reserves; disruptions such as Hurricanes Katrina and Rita; and demand fluctuations with GDP growth and cost, among other factors.[101] If a carbon tax is enacted, the EIA projects it will significantly increase demand for natural gas and will lead to an increase in gas prices by shifting the generation mix from coal to gas.[102] Even a carbon tax as low as $10 per ton will lead to unfavorable conditions if the utility invests in gas generation only.

As noted in the scenario analysis results, although wind can be more expensive to bring online, having some wind generation capacity significantly narrows the NPV cost distribution, especially in the case of an unfavorable gas price future. According our model, when a utility does not hedge at all with wind, they have a long NPV cost band from $4.7 billion to $10.1 billion that covers all the outcomes from the low natural gas price case without carbon tax to the high gas price case with a carbon tax of $25 per ton. If the utility hedges with 20% wind at a price of $55/MWh, the cost band becomes shorter, and the utility could avoid $90 million in costs under the high natural gas price scenario and up to $774 million in costs if the high carbon tax scenario were to occur. Additionally, if utilities diversify their portfolio with wind, they can count on the wind energy to meet demand during times of natural gas shortages or price spikes.

- **Without the PTC, wind becomes a more expensive hedging tool**

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[100] TVA Integrated Resource Plan Working Group, *Tennessee Valley Authority 2015 Integrated Resource Plan, (*November 5, 2013).
[101] Brattle Group, "Managing Natural Gas."
[102] EIA, *Annual Energy Outlook 2013*.

The expiration of the PTC in December 2013 has created great uncertainty for the wind industry. According to the American Wind Energy Association, only 1,084 MW of new capacity was installed in 2013 compared to the record-breaking 13,131 MW added in 2012.[103] Based on our analysis, the tipping intervals for PPA prices that make wind competitive against gas generation are $52 to $55/MWh in the reference case, $41 to $44/MWh in the low natural gas price case, and $59 to $62/MWh in high gas price case. The PTC is equivalent to $23/MWh, and without the credit, it will be difficult for PPA prices to fall below these intervals to compete with other forms of power generation.[104] Wind's portfolio and hedging attribute will remain the same, although the benefits will come at a higher price without the PTC.

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[103] AWEA, "Fourth Quarter 2013 Market Report."
[104] Bolinger, *Long-Term Hedge Value of Wind*.

Appendix

1. Investment option parameters

Source: IECM (NGCC Plant with wet cooling tower and GE 7FA gas turbines)

Investment Option 1: NG Plant (5 turbines)

Total Capital Requirement M$ in 2011	$1,414.63
Net capacity (MW)	1,356
Capacity factor (%)	75%
Net heat rate (btu/kWh)	7,058
SO2 emissions rate (lbs/MMBtu)	0
NOx emissions rate (lbs/MMBtu)	0.03
CO2 emissions rate (lbs/MMBtu)	117.7
Operating constraints	NA
PPA Annual Cost	NA

Annual Operating Hours (hours)	6,570
Annual Power Generation (MWh/yr)	8,908,920
Fuel Use (MMBtu)	62,879,157
Wind Percentage	0%

Fixed O&M (M$)	$19.28
Fixed O&M growth rate (%)	$2.00
Variable O&M (M$)	$3.17
Variable O&M growth rate (%)	$2.00

Investment Option 2: NG Plant (4 turbines) + Wind Energy

Total Capital Requirement M$ in 2011	$2,358.66
Net capacity (MW)	1,085
Capacity factor (%)	75%
Net heat rate (btu/kWh)	7,058
SO2 emissions rate (lbs/MMBtu)	0
NOx emissions rate (lbs/MMBtu)	0.027
CO2 emissions rate (lbs/MMBtu)	117.7
Operating constraints	NA
PPA Annual Cost	$97.93

Annual Operating Hours (hours)	6,570
Annual Power Generation (MWh/yr)	7,128,450
Fuel Use (MMBtu)	50,312,600
Wind Percentage	20%

Fixed O&M (M$)	$16.21
Fixed O&M growth rate (%)	$2.00
Variable O&M (M$)	$2.53
Variable O&M growth rate (%)	$2.00

Investment Option 3: NG Plant (3 turbines) + Wind Energy

Total Capital Requirement M$ in 2011	$3,297.04
Net capacity (MW)	814
Capacity factor (%)	75%
Net heat rate (btu/kWh)	7,058
SO2 emissions rate (lbs/MMBtu)	0
NOx emissions rate (lbs/MMBtu)	0.027
CO2 emissions rate (lbs/MMBtu)	117.7
Operating constraints	NA
PPA Annual Cost	$196.00

Annual Operating Hours (hours)	6,570
Annual Power Generation (MWh/yr)	5,345,352
Fuel Use (MMBtu)	37,727,494
Wind Percentage	40%

Fixed O&M (M$)	$13.11
Fixed O&M growth rate (%)	$2.00
Variable O&M (M$)	$1.90
Variable O&M growth rate (%)	$2.00

Investment Option 4: NG Plant (2 turbines) + Wind Energy

Total Capital Requirement M$ in 2011	$4,231.66
Net capacity (MW)	542
Capacity factor (%)	75%
Net heat rate (btu/kWh)	7,058
SO2 emissions rate (lbs/MMBtu)	0
NOx emissions rate (lbs/MMBtu)	0.027
CO2 emissions rate (lbs/MMBtu)	117.7
Operating constraints	NA
PPA Annual Cost	$293.99

Annual Operating Hours (hours)	6,570
Annual Power Generation (MWh/yr)	3,563,568
Fuel Use (MMBtu)	25,151,663
Wind Percentage	60%

Fixed O&M (M$)	$9.98
Fixed O&M growth rate (%)	$2.00
Variable O&M (M$)	$1.27
Variable O&M growth rate (%)	$2.00

Investment Option 5: NG Plant (1 turbine) + Wind Energy

Total Capital Requirement M$ in 2011	$5,162.69
Net capacity (MW)	271
Capacity factor (%)	75%
Net heat rate (btu/kWh)	7,058
SO2 emissions rate (lbs/MMBtu)	0
NOx emissions rate (lbs/MMBtu)	0.027
CO2 emissions rate (lbs/MMBtu)	117.7
Operating constraints	NA
PPA Annual Cost	$391.99

Annual Operating Hours (hours)	6,570
Annual Power Generation (MWh/yr)	1,781,784
Fuel Use (MMBtu)	12,575,831
Wind Percentage	80%

Fixed O&M (M$)	$6.80
Fixed O&M growth rate (%)	$2.00
Variable O&M (M$)	$0.63
Variable O&M growth rate (%)	$2.00

Investment Option 6: Wind Energy

Source: LBNL wind PPA sample

Total Capital Requirement M$ in 2011	$6,080.31
Net capacity (MW)	-
Capacity factor (%)	-
Net heat rate (btu/kWh)	-
SO2 emissions rate (lbs/MMBtu)	-
NOx emissions rate (lbs/MMBtu)	-
CO2 emissions rate (lbs/MMBtu)	-
Operating constraints	-
PPA Annual Cost	$489.99

Annual Operating Hours (hours)	0
Annual Power Generation (MWh/yr)	0
Fuel Use (MMBtu)	0
Wind Percentage	100%

Fixed O&M (M$)	-
Fixed O&M growth rate (%)	-
Variable O&M (M$)	-
Variable O&M growth rate (%)	-

2. National Average Levelized PPA prices

Source: Bolinger and Wiser, 2012 Wind Technologies Market Report 2013

Year	(2012 $/MWh)
2003	34.05
2004	38.59
2005	36.81
2006	50.05
2007	51.12
2008	63.67
2009	67.30
2010	60.57
2011	41.85
2012	38.11

3. Levelized PPA prices for the Southeast Region

Source: LBNL wind PPA sample

Utility (Buyer)	Wind Farm	State	Project Name Plate capacity (MW)	PPA contract length (years)	PPA date signed	PPA start date	Levelized PPA price ($/MWh)	Capacity factor (%)
TVA	White Oak	IL	150.0	20	Nov-09	Jan-12	67.50	36
TVA	Cimarron	KS	165.6	20	May-11	Dec-12	64.00	40
TVA	Bishop Hill	IL	209.4	20	Nov-09	Jul-12	77.50	35
TVA	Caney River	KS	199.8	-	-	Jan-12	56.00	42
TVA	California Ridge	IL	214.4	20	May-11	Dec-12	69.00	39
Alabama Power	Chisholm View	OK	235.2	20	Jun-11	Dec-12	32.21	40

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